South Coast
Air Quality Management District
21865 Copley Drive, Diamond Bar, CA 91765-4178
(909) 396-2000 · www.aqmd.gov

October 31, 2006

Mr. Lorne Prescott
Project Manager
California Energy Commission
1516 9th Street
Sacramento, CA 95814-5512

Subject: Walnut Creek Energy Project (05-AFC-2) to be located at 911 Bixby Drive, City of Industry, CA

Dear Mr. Prescott:

This letter is to inform you that the South Coast Air Quality Management District (AQMD) has completed our analysis of the proposed project as described above. Attached for your review is a Preliminary Determination of Compliance (PDOC) that includes the AQMD's engineering analysis.

The proposed facility will be a new major stationary source, and based on the potential to emit the project is subject to EPA review and public notice requirements. Both of these tasks will be undertaken shortly. The final permit to construct is contingent on the CEC approval of the project. In addition, the applicant will be required to obtain emission reduction credits for CO, PM_{10}, VOC, and SOx before the final permit to construct can be issued. Prior to operation of the proposed project, the applicant will be required to obtain sufficient NOx RECLAIM Trading Credits to offset the total facility emissions for the first year of operation.

If you have any questions or wish to provide comments regarding this project, please call Mr. Kenneth L. Coats (909) 396-2527 or Mr. John Yee (909) 396-2531.

Very truly yours,

Michael D. Mills

Michael D. Mills, P.E.
Senior Manager
General Commercial & Energy Team
Engineering and Compliance

MDM:MYL:JTY:klc

Attachments

cc: Tom McCabe, Edison Mission Energy

CERTIFIED MAIL
Return Receipt Required

WALNUT CREEK ENERGY, LLC; ENGINEERING ANALYSIS FOR A NEW 500 MW SIMPLE CYCLE POWER PLANT

COMPANY NAME AND ADDRESS

Walnut Creek Energy, LLC
% Edison Mission Energy
18101 Von Karman Avenue
Irvine, CA 92612
Contact: Mr. Thomas J. McCabe, Jr
AQMD Facility ID: 146536

EQUIPMENT LOCATION

911 Bixby Drive
City of Industry, CA 91744

EQUIPMENT DESCRIPTION

Section H of the Facility Permit

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
GAS TURBINE, UNIT NO. 1, NATURAL GAS, GENERAL ELECTRIC MODEL LMS100PA, SIMPLE CYCLE, 904 MMBTU/HR AT 45 DEGREES F WITH WATER INJECTION, WITH A/N 450894 GENERATOR, 104 MW	D1	C3	NOX: MAJOR SOURCE	CO: 6.0 PPMV NATURAL GAS (4) [Rule 1303(a)(1)-BACT]; **CO:** 2000 PPMV (5) [Rule 407] **NOX:** 119 PPMV NATURAL GAS (8) [40CFR60 Subpart GG]; **NOX:** 123.46 LB/MMCF (1) [Rule 2012] **NOX** 10.86 LB/MMCF NATURAL GAS (1)[Rule 2012] **NOX** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT] **VOC:** 2.0 PPMV (4)[Rule 1303(a)(1)-BACT] **PM10**: 0.01 GRAIN/DSCF (5A) [Rule 475]; **PM10**: 0.1 GRAIN/DSCF (5) [Rule 409]; **PM10**: 11 LB/HR (5B) [Rule 475] **SOX**: 150 PPMV (8) [40 CFR60 Subpart GG]; **SO2**: (9) Acid Rain Provisions	A63.1, A63.2, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, D12.1, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, I296.1, K40.1, K67.1

EQUIPMENT DESCRIPTION (continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
CO OXIDATION CATALYST NO. 1, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450899	C3	D1 C4			
SELECTIVE CATALYTIC REDUCTION NO. 1, HALDOR-TOPSOE DNX-920, WITH 718 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 28 FT 8 IN; WIDTH: 20 FT 3 IN; DEPTH: 1 FT 8 IN; WITH NH3 INJECTION GRID A/N: 450899	C4	S6 C3		**NH3:** 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.4 D12.2 D12.3 D12.4 E179.1 E179.2 E193.1
STACK NO. 1, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450894	S6	C4			
GAS TURBINE, UNIT NO. 2, NATURAL GAS, GENERAL ELECTRIC MODEL LMS100PA, SIMPLE CYCLE, 904 MMBTU/HR AT 45 DEGREES F WITH WATER INJECTION, WITH A/N 450895 GENERATOR, 104 MW	D7	C9	NOX: MAJOR SOURCE	**CO:** 6.0 PPMV NATURAL GAS (4) [Rule 1303(a)(1)-BACT]; **CO:** 2000 PPMV (5) [Rule 407] **NOX:** 119 PPMV NATURAL GAS (8) [40CFR60 Subpart GG]; **NOX:** 123.46 LB/MMCF (1) [Rule 2012] **NOX** 10.86 LB/MMCF NATURAL GAS (1)[Rule 2012] **NOX** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT] **VOC:** 2.0 PPMV (4)[Rule 1303(a)(1)-BACT] **PM10**: 0.01 GRAIN/DSCF (5A) [Rule 475]; **PM10**: 0.1 GRAIN/DSCF (5) [Rule 409]; **PM10**: 11 LB/HR (5B) [Rule 475] **SOX**: 150 PPMV (8) [40 CFR60 Subpart GG]; **SO2**: (9) Acid Rain Provisions	A63.1, A63.2, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, D12.1, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, I296.1, K40.1, K67.1

EQUIPMENT DESCRIPTION (continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
CO OXIDATION CATALYST NO. 2, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450900	C9	D7 C10			
SELECTIVE CATALYTIC REDUCTION NO. 2, HALDOR-TOPSOE DNX-920, WITH 718 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 28 FT 8 IN; WIDTH: 20 FT 3 IN; DEPTH: 1 FT 8 IN; WITH NH3 INJECTION GRID A/N: 450900	C10	S12 C9		**NH3:** 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.4 D12.2 D12.3 D12.4 E179.1 E179.2 E193.1
STACK NO. 2, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450895	S12	C10			
GAS TURBINE, UNIT NO. 3, NATURAL GAS, GENERAL ELECTRIC MODEL LMS100PA, SIMPLE CYCLE, 904 MMBTU/HR AT 45 DEGREES F WITH WATER INJECTION, WITH A/N 450896 GENERATOR, 104 MW	D13	C15	NOX: MAJOR SOURCE	**CO:** 6.0 PPMV NATURAL GAS (4) [Rule 1303(a)(1)-BACT]; **CO:** 2000 PPMV (5) [Rule 407] **NOX:** 119 PPMV NATURAL GAS (8) [40CFR60 Subpart GG]; **NOX:** 123.46 LB/MMCF (1) [Rule 2012] **NOX** 10.86 LB/MMCF NATURAL GAS (1)[Rule 2012] **NOX** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT] **VOC:** 2.0 PPMV (4)[Rule 1303(a)(1)-BACT] **PM10**: 0.01 GRAIN/DSCF (5A) [Rule 475]; **PM10**: 0.1 GRAIN/DSCF (5) [Rule 409]; **PM10**: 11 LB/HR (5B) [Rule 475] **SOX**: 150 PPMV (8) [40 CFR60 Subpart GG]; **SO2**: (9) Acid Rain Provisions	A63.1, A63.2, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, D12.1, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, I296.1, K40.1, K67.1

Equipment Description (Continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
CO OXIDATION CATALYST NO. 3, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450901	C15	D13 C16			
SELECTIVE CATALYTIC REDUCTION NO. 3, HALDOR-TOPSOE DNX-920, WITH 718 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 28 FT 8 IN; WIDTH: 20 FT 3 IN; DEPTH: 1 FT 8 IN; WITH NH3 INJECTION GRID A/N: 450901	C16	S18 C15		**NH3:** 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.4 D12.2 D12.3 D12.4 E179.1 E179.2 E193.1
STACK NO. 3, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450896	S18	C16			
GAS TURBINE, UNIT NO. 4, NATURAL GAS, GENERAL ELECTRIC MODEL LMS100PA, SIMPLE CYCLE, 904 MMBTU/HR AT 45 DEGREES F, WITH WATER INJECTION, WITH A/N 450897 GENERATOR, 104 MW	D19	C21	NOX: MAJOR SOURCE	**CO:** 6.0 PPMV NATURAL GAS (4) [Rule 1303(a)(1)-BACT]; **CO:** 2000 PPMV (5) [Rule 407] **NOX:** 119 PPMV NATURAL GAS (8) [40CFR60 Subpart GG] **NOX:** 123.46 LB/MMCF (1) [Rule 2012] **NOX** 10.86 LB/MMCF NATURAL GAS (1)[Rule 2012] **NOX** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT] **VOC:** 2.0 PPMV (4)[Rule 1303(a)(1)-BACT] **PM10**: 0.01 GRAIN/DSCF (5A) [Rule 475]; **PM10**: 0.1 GRAIN/DSCF (5) [Rule 409]; **PM10**: 11 LB/HR (5B) [Rule 475] **SOX**: 150 PPMV (8) [40 CFR60 Subpart GG]; **SO2**: (9) Acid Rain Provisions	A63.1, A63.2, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, D12.1, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, I296.1, K40.1, K67.1

Equipment Description (Continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
CO OXIDATION CATALYST NO. 4, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450904	C21	D19 C22			
SELECTIVE CATALYTIC REDUCTION NO. 4, HALDOR-TOPSOE DNX-920, WITH 718 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 28 FT 8 IN; WIDTH: 20 FT 3 IN; DEPTH: 1 FT 8 IN; WITH NH3 INJECTION GRID A/N: 450904	C22	S24 C21		**NH3:** 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.4 D12.2 D12.3 D12.4 E179.1 E179.2 E193.1
STACK NO. 4, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450897	S24	C22			
GAS TURBINE, UNIT NO. 5, NATURAL GAS, GENERAL ELECTRIC MODEL LMS100PA, SIMPLE CYCLE, 904 MMBTU/HR AT 45 DEGREES F WITH WATER INJECTION, WITH A/N 450898 GENERATOR, 104 MW	D25	C27	NOX: MAJOR SOURCE	**CO:** 6.0 PPMV NATURAL GAS (4) [Rule 1303(a)(1)-BACT]; **CO:** 2000 PPMV (5) [Rule 407] **NOX:** 119 PPMV NATURAL GAS (8) [40CFR60 Subpart GG] **NOX:** 123.46 LB/MMCF (1) [Rule 2012] **NOX** 10.86 LB/MMCF NATURAL GAS (1)[Rule 2012] **NOX** 2.5 PPMV NATURAL GAS (4)[Rule 2005-BACT] **VOC:** 2.0 PPMV (4)[Rule 1303(a)(1)-BACT] **PM10**: 0.01 GRAIN/DSCF (5A) [Rule 475]; **PM10**: 0.1 GRAIN/DSCF (5) [Rule 409]; **PM10**: 11 LB/HR (5B) [Rule 475] **SOX**: 150 PPMV (8) [40 CFR60 Subpart GG] **SO2**: (9) Acid Rain Provisions	A63.1, A63.2, A99.1, A99.2, A99.3, A99.4, A195.1, A195.2, A195.3, A327.1, C1.1, D12.1, D29.1, D29.2, D29.3, D82.1, D82.2, E193.1, I296.1, K40.1, K67.1

Equipment Description (Continued)

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 1: INTERNAL COMBUSTION					
System 1: GAS TURBINES, POWER GENERATION					
CO OXIDATION CATALYST NO. 5, ENGLEHARD CAMET, 72 CUBIC FEET OF TOTAL CATALYST VOLUME, WITH A/N: 450907	C27	D25 C28			
SELECTIVE CATALYTIC REDUCTION NO. 5, HALDOR-TOPSOE DNX-920, WITH 718 CUBIC FEET OF TOTAL CATALYST VOLUME, HEIGHT: 28 FT 8 IN; WIDTH: 20 FT 3 IN; DEPTH: 1 FT 8 IN; WITH NH3 INJECTION GRID A/N: 450907	C28	S30 C27		**NH3:** 5.0 PPMV (4) [Rule 1303(a)(1)-BACT]	A195.4 D12.2 D12.3 D12.4 E179.1 E179.2 E193.1
STACK NO. 5, DIAMETER: 13 FT 6 IN, HEIGHT: 90 FT A/N: 450898	S30	C28			
System 2: EMERGENCY FIRE PUMP					
INTERNAL COMBUSTION ENGINE, EMERGENCY FIRE, DIESEL FUEL, LEAN BURN, CLARKE, MODEL JW6H-UF50, 340 BHP WITH AFTERCOOLER, TURBOCHARGER, A/N: 450908	D34		NOX: PROCESS UNIT	**NOX+NMHC:** 4.8 GM/BHP-HR DIESEL (4) [RULE 2005]; **NOX:** 469 LB/1000 GAL DIESEL (1) [RULE 2012] **CO:** 0.45 GM/BHP-HR DIESEL (4) [RULE 1303] **PM10:** 0.09 GM/BHP-HR DIESEL (4) [RULE 1303] **SOX:** 0.0055 GM/BHP-HR DIESEL (4) [RULE 2005];	C1.3, B61.1, D12.5, D12.6, E193.1, E193.2, I296.2, K67.2
Process 2: INORGANIC CHEMICAL STORAGE					
STORAGE TANK, TK-1, FIXED ROOF, 19 PERCENT AQUEOUS AMMONIA, DIAMETER: 12'-0"; HEIGHT: 12'-0"; 16,000 GALLONS WITH PRV SET AT 25 PSIG WITH A/N: 451185	D31				C157.1, E144.1,E193.1

Section D of the Facility Permit

Equipment	ID No.	Connected To	RECLAIM Source Type/ Monitoring Unit	Emissions And Requirements	Conditions
Process 3: RULE 219 EXEMPT EQUIPMENT SUBJECT TO SOURCE SPECIFIC RULES					
RULE 219 EXEMPT EQUIPMENT, COATING EQUIPMENT, PORTABLE, ARCHITECTURAL COATING	E32			**VOC:** (9) [Rule 1113], Rule 1171	K67.3
RULE 219 EXEMPT EQUIPMENT, EXEMPT HAND WIPING OPERATIONS	E33			**VOC:** (9) [Rule 1171]	

BACKGROUND

In order to pursue the development of a proposed natural gas fired peaker project, Edison Mission Energy (EME) has organized a special purpose entity known as Walnut Creek Energy, LLC a Delaware limited liability company, to develop, own and operate the proposed peaker project. Walnut Creek Energy, LLC is a wholly-owned subsidiary of EME.

Walnut Creek Energy, LLC is proposing to construct a new power plant which will consist of five (5) combustion-turbine-generators (CTGs) for a total rated peak generating capacity of 520 MW at 45°F. The gas turbines will be General Electric LMS100 units. Each turbine will drive a generator rated at 104 MW at 45°F. The project is expected to have an annual capacity factor of approximately 20 to 40 percent, depending on weather-related customer demand, load growth, hydroelectric supplies, generating unit retirements, and other factors.

Each of the proposed CTGs will be configured in simple cycle, and therefore there will be no heat recovery steam generators (HRSG), duct burners, or steam turbines used at this plant. The net power generated (after taking away auxiliary power consumption) will be derived solely from the five generators. Selective catalytic reduction (SCR) systems and CO oxidation catalysts will be utilized for control of NOx and CO emissions, respectively. One 16,000 gallon ammonia (NH_3) storage tank will be constructed for the storage of 19% aqueous ammonia which is part of the SCR process. A 5-cell mechanical drift cooling tower will provide heat removal for the gas turbine auxiliary cooling requirements. The site will also employ a 340 bhp diesel emergency fire pump engine.

The California Energy Commission (CEC) has the statutory responsibility for certification of power plants rated at 50 MW and larger, including any related facilities such as transmission lines, fuel supply lines, and water pipelines. The CEC's 12-month, one-stop permitting process is a certified regulatory program under the California Environmental Quality Act (CEQA) and also includes several opportunities for public and inter-agency participation. The CEC's certification process subsumes all requirements of state, local, or regional agencies otherwise required before a new plant is constructed. The CEC coordinates its review of the facility with the federal agencies that will be issuing permits to ensure that the CEC certification incorporates conditions of certification that would be required by various federal agencies. Since the Walnut Creek Energy Project (WCEP) will be rated at greater than 50 megawatts, it is subject to the CEC's 12-month certification process. As part of this process, WCEP submitted an application for certification (05-AFC-2) to the CEC on November 22, 2005 seeking certification for the new power plant. In addition to the CEC certification process, WCEP submitted applications to AQMD seeking Permits to Construct for the new power plant. The following table shows the corresponding application numbers (A/Ns):

Table 1 - Applications for Permits to Construct Submitted to AQMD

Application Number	Equipment Description
450894	Gas Turbine No. 1
450895	Gas Turbine No. 2
450896	Gas Turbine No. 3
450897	Gas Turbine No. 4
450898	Gas Turbine No. 5
450899	SCR/CO Catalyst for Turbine No. 1
450900	SCR/CO Catalyst for Turbine No. 2
450901	SCR/CO Catalyst for Turbine No. 3
450904	SCR/CO Catalyst for Turbine No. 4
450907	SCR/CO Catalyst for Turbine No. 5
450908	Emergency Fire Pump Engine
451185	Aqueous Ammonia Storage Tank
450854	Initial Title V Application

Each of the applications were submitted to the AQMD on November 30, 2005, except for the application for the NH_3 storage tank, which was submitted on December 7, 2005. AQMD deemed the applications complete on December 13, 2005. Because WCEP will have the potential to generate electricity greater than 25 MW, it will be subject to the federal Acid Rain requirements and therefore the federal Title V permitting requirements apply. WCEP will also be included in the NOx RECLAIM program.

Processing Fee Summary

On November 30, 2005, AQMD received the thirteen (13) applications shown in the table above along with a processing fee of $56,001.00. The $56,001.00 processing fee covers the processing fees for both the WCEP and another proposed power plant (Sun Valley Energy Project, aka SVEP) to be located in Romoland, CA. The applicant also included a signed form 400-XPP and the appropriate fees for expedited permit processing. The five LMS100s are identical and therefore, four of these devices receive a 50% discount off of the original processing fee of $3,364.77. In addition, the five SCR/CO catalysts are identical and therefore, four of these devices receive a 50% discount off of the original processing fee of $2,437.95. The normal processing fees are multiplied by 1.5 for expedited processing. A fee summary for WCEP is shown in the table below.

Table 2 - Summary of Processing Fees for WCEP

A/N	Submittal Date	Deemed Complete	Equipment	Schedule	Processing Fee	XPP	TOTAL
450894	11-30-2005	12-13-2005	LMS100 Gas Turbine No. 1	D	$3,364.77	1.5	$5,047.16
450895	11-30-2005	12-13-2005	LMS100 Gas Turbine No. 2	D	$1,682.39	1.5	$2,523.59
450896	11-30-2005	12-13-2005	LMS100 Gas Turbine No. 3	D	$1,682.39	1.5	$2,523.59
450897	11-30-2005	12-13-2005	LMS100 Gas Turbine No. 4	D	$1,682.39	1.5	$2,523.59
450898	11-30-2005	12-13-2005	LMS100 Gas Turbine No. 5	D	$1,682.39	1.5	$2,523.59
450899	11-30-2005	12-13-2005	SCR/CO Catalyst No. 1	C	$2,437.95	1.5	$3,856.93
450900	11-30-2005	12-13-2005	SCR/CO Catalyst No. 2	C	$1,218.98	1.5	$1,828.47
450901	11-30-2005	12-13-2005	SCR/CO Catalyst No. 3	C	$1,218.98	1.5	$1,828.47
450904	11-30-2005	12-13-2005	SCR/CO Catalyst No. 4	C	$1,218.98	1.5	$1,828.47
450907	11-30-2005	12-13-2005	SCR/CO Catalyst No. 5	C	$1,218.98	1.5	$1,828.47
450908	11-30-2005	12-13-2005	Emergency Fire Pump	B	$1,541.34	1.5	$2,312.01
451185	12-7-2005	12-13-2005	Ammonia Storage Tank	A	$967.11	1.5	$1,450.67
450854	11-30-2005	12-13-2005	Title V Application	N/A	$1.007.60	N/A	$1,007.60
						WCEP TOTAL PROCESSING FEE	**$31,082.61**

Given that the equipment at both proposed power plants is identical, the total processing fee for both the WCEP and SVEP facilities is 2 * $31,082.61 = $62,165.22. However, the applicant only submitted a total of $56,001.00 to cover both proposed plants, leaving a deficiency of $6,164.22. Therefore the applicant will be required to submit the difference of $6,164.22 prior to approving the SVEP applications.

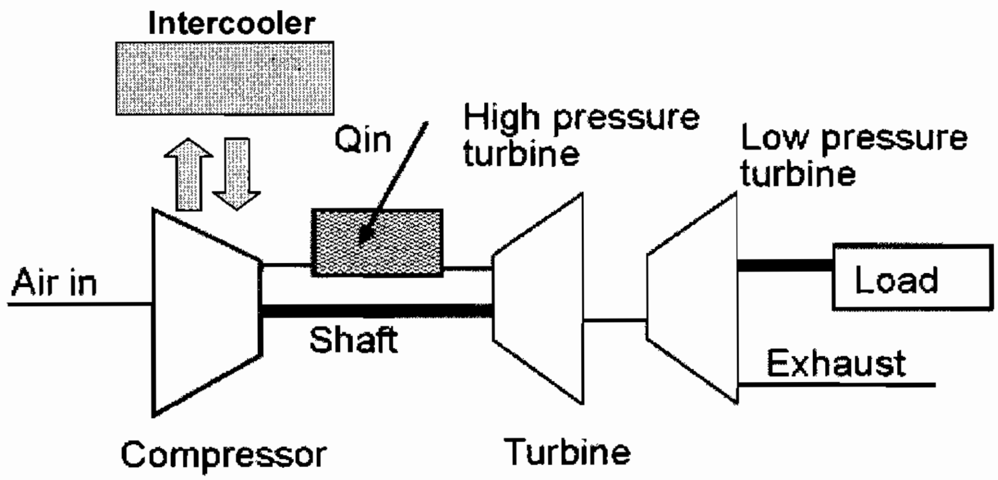
Site Description
The proposed location of WCEP is on an 11.48 acre parcel currently owned by the Industry Urban Development Agency (Development Agency). The parcel is located at 911 Bixby Drive, City of Industry, CA 91744. The parcel is entirely covered with a large warehouse building and asphalt paving and is currently in use as a commercial distribution facility. The Development Agency has planned this parcel for redevelopment and plans to demolish the existing structure in the near future. EME has entered into a lease option agreement for the project site. The lease option will be assigned to and exercised by Walnut Creek Energy, LLC who will take physical possession of the site from the Development Agency after the demolition has taken place. The City of Industry is in the process of reviewing a Negative Declaration for the demolition in order to make the parcel available for a higher-value industrial use. WCEP will be located in an area zoned for industrial uses. The project site is located within the boundaries of the La Puente Mexican land grant rancho and does not have township, range, and section designations. The Los Angeles County Assessor's parcel designation is 8242-013-901.

COMPLIANCE RECORD
WCEP is a new facility and construction on the proposed power plant has not yet begun. No additional existing sources are presently operating under the above facility ID. As a confirmation, the AQMD's Compliance Tracking System database indicates no compliance activity for this facility ID.

PROCESS DESCRIPTION
The proposed power plant will operate in simple cycle configuration and will employ five (5) General Electric LMS100 combustion gas turbines, each of which employ off-engine intercooling technology with the use of water and an external heat exchanger for increased thermal efficiency. The LMS100 system includes a 3-spool gas turbine configured with an intercooler located between the low-pressure compressor (LPC) and the high-pressure compressor (HPC).

Intercooling
Intercooling provides significant benefits to the Brayton cycle by reducing the work of compression for the HPC, which allows for higher pressure ratios and thereby increasing overall efficiency. For the LMS100, the cycle pressure ratio is 42:1. The reduced inlet temperature for the HPC allows increased mass flow resulting in higher specific power. The lower resultant compressor discharge temperature provides colder cooling air to the turbines, which in turn allows increased firing temperatures equivalent to those of the LM6000, producing an overall cycle efficiency in excess of 46% in simple cycle configuration. This represents a 10% increase in the efficiency over the LM6000. The LMS100 can be configured with two different types of intercooling systems, with the first type being a wet intercooling system which uses an air-to-water heat exchanger (shell and tube design) and an evaporative cooling tower. The second system consisting of bellows expansion joints, moisture separator, variable bleed valve system, and associated piping and involves a dry intercooling system requiring no water. It uses an air-to-air heat exchanger constructed with panels of finned tubes mounted in an A-frame configuration. All five LMS100s proposed for construction at WCEP will be configured with a wet intercooling system. A general diagram of the LMS100 employing wet intercooling technology to be used at the WCEP is shown in the diagram below.

LMS100 Gas Turbine with Intercooler



WCEP will connect to Southern California Edison's (SCE) electrical transmission system at the Walnut Substation, which is located approximately 250 feet south of the proposed project site. This connection will require 600 feet of 230-kilovolt (kV) transmission line and two transmission towers to be located adjacent to the substation within SCE's transmission corridor. Interconnection at this specific substation minimizes downstream impacts to SCE's transmission system while providing efficient peaking power for use during peak demand as projected by SCE. Reclaimed water for the cooling tower and evaporative cooler make-up, site landscape irrigation, and demineralized water make-up will be supplied via a direct connection to a 12 inch diameter reclaimed water pipeline at the corner of Bixby Drive and Chestnut Street, adjacent to the project entrance, through a 12 inch diameter pipe extending approximately 30 feet from the project boundary into Bixby Drive. The Rowland Water District will supply on the average, approximately 827 acre-feet per year of reclaimed water from the San Jose Creek Wastewater Reclamation Plant. The following table lists the technical specifications for the General Electric LMS100 CTG.

Table 3 - Combustion Turbine Generator Specifications[1]

Parameter	Specifications
Manufacturer	General Electric
Model	LMS100PA[2]
Fuel Type	PUC[3] Quality Natural Gas
Natural Gas Heating Value	1,050 BTU/scf
Gas Turbine Heat Input (HHV)	904 MMBTU/hr at 45°F and 60% relative humidity
Fuel Consumption	0.861 MMSCF/hr[4]
Gas Turbine Exhaust Flow	364,419 DSCFM
Gas Turbine Exhaust Temperature	762°F
Exhaust Moisture	6-8%
Gas Turbine Power Generation	104 MW
Net Plant Heat Rate, LHV	8,061 BTU/kW-hr

[1] Values in this table are on a per-turbine basis
[2] GE Manufactures two versions of the LMS100 CTG. WCEP plans to install the LMS100PA. The PA model utilizes water injection for NOx abatement while the PB version utilizes dry low emission (DLE) combustors for NOx abatement.
[3] PUC is the acronym for the California Public Utilities Commission
[4] Represents the maximum possible fuel consumption of the CTG, based on 904 MMBTU/hr heat input and 1,050 BTU/scf fuel heat content. However, the emission calculations will be based on a worst-case operating scenario as identified by the applicant, which may result in a lower fuel usage depending on the ambient temperature, the employment and rate of intercooling, water injection rates, and electrical load generated.

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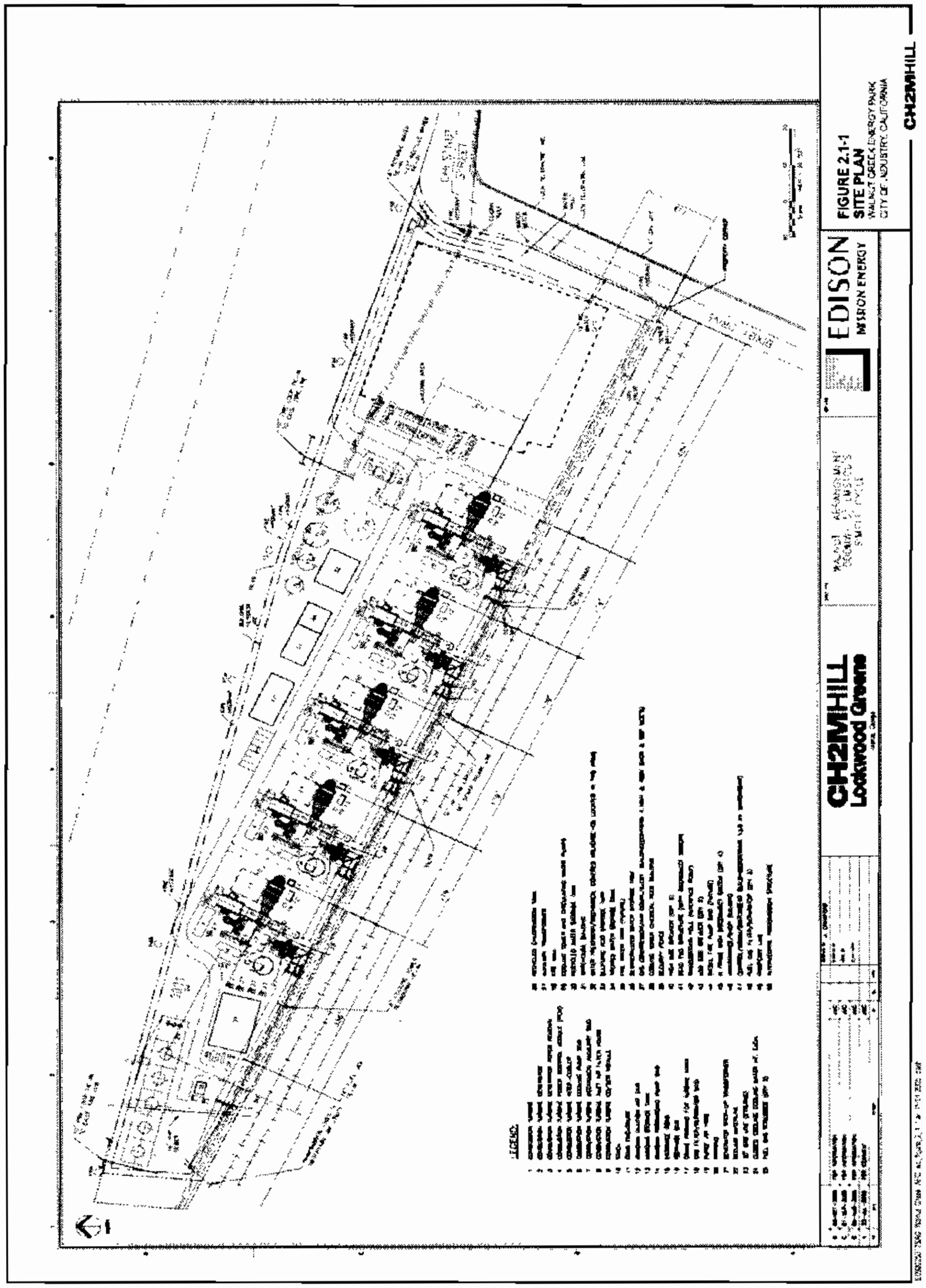
ENGINEERING AND COMPLIANCE DIVISION	APPLICATION NO. 450894 (Master File)	DATE 10-27-2006
ENGINEERING ANALYSIS / EVALUATION	PROCESSED BY: Ken Coats	REVIEWED BY:



The site plan shown on the previous page was prepared for WCEP by CH2MHILL and shows the general layout of the proposed facility. The project site is located in an industrial area and is surrounded to the south, east, and west by warehousing and other industrial uses. To the north is an SCE utility corridor used for transmission lines. Beyond the corridor is the San Jose Flood Control Channel, and beyond that to the north, an intermodal rail/truck terminal. Residential areas are located in the City of La Puente to the north, beyond the industrial areas that are adjacent to the project site, and in unincorporated areas of the Los Angeles County community of Hacienda Heights to the south.

Definition of a Peaking Unit in Rule 2012
A traditional peaking unit is defined as a turbine which is used intermittently to produce energy on a demand basis and does not operate more than 1,300 hours per year. This definition is found in Rule 2012-Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen (NOx) Emissions, Attachment A-F as amended December 5, 2003. WCEP will have the potential to operate for about 3,468 hours/year inclusive of start-up, shutdown, commissioning, maintenance, (if any) and normal operations. Since the annual hours of operation will exceed that which is allowed for a traditional peaking unit under Rule 2012, the LMS100s will not be classified as official peaking units in the equipment descriptions. The CTGs will be listed as a NOx Major Source under Rule 2012.

Air Pollution Control (APC) System
All five CTGs will utilize two primary means for the reduction of NOx emissions. On the front end, WCEP will rely on the use of demineralized water for water injection directly into the CTGs. The demineralized water will be produced by reverse osmosis (RO) and an ion exchange system and will be stored in a 100,000 gallon demineralized water storage tank. The use of demineralized water injection will reduce the 1-hour average NOx concentration to 25 ppmv on a dry basis at 15% O_2 prior to entry to the selective catalytic reduction (SCR) units. On the back end, and SCR catalyst with ammonia injection will be used downstream of each CTG for further reduction of NOx emissions and a CO oxidation catalyst will be used downstream of each CTG for CO emissions reduction. As a result, the NOx emissions will be limited to 2.5 ppmv, 1-hour average, dry basis at 15% O_2. CO emissions will be limited to 6.0 ppmv, 1-hour average, dry basis, at 15% O_2. ROG emissions will be limited to 2.0 ppmv, dry basis at 15% O_2. SOx and PM_{10} emissions will be mitigated through the use of PUC quality natural gas. Detailed descriptions of the air pollution control system are given in the next section. The CO catalyst is permitted together with the SCR catalyst.

Selective Catalytic Reduction/CO Catalyst Systems (A/Ns 450899, 450900, 450901, 450904, & 450907)
Table 4 below shows the specifications for the SCR manufacturer to be used for the simple cycle CTGs.

Table 4 - Selective Catalytic Reduction

Catalyst Properties	Specifications
Manufacturer	Haldor-Topsoe
Catalyst Description	Ti V honeycomb single layer structure
Catalyst Model No.	DNX 920
Catalyst Volume	850 ft^3
Guaranteed Life	Earliest of 20,000 hrs from first gas-in or 51 months from contracted delivery.
Space Velocity	23,580 hr^{-1}
Ammonia Injection Rate	190 lb/hr
NOx removal efficiency	>90%
NOx at stack outlet	2.5 ppmv at 15% O_2
Exhaust Temperature	740-800°F

The SCR catalyst will use ammonia injection in the presence of the catalyst to reduce NOx. Diluted ammonia vapor will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst module. The subsequent chemical reaction will reduce NOx to elemental nitrogen (N_2) and water, resulting in NOx concentrations in the exhaust gas at no greater than 2.5 ppmvd at 15% O_2 on a 1-hour average.

<u>CO Oxidation Catalyst</u>
The CO oxidation catalyst will be installed within the catalyst housing which will reduce CO in the exhaust gas to no greater than 6 ppmvd at 15% O_2, on a 1-hour average. The exhaust from each catalyst housing will be discharged from individual 90-foot tall, 13.5 foot diameter exhaust stacks. Each CTG will have its own individual stack.

WCEP has indicated that the CO catalyst manufacturer is to be Englehard. The following table lists the CO catalyst specifications for both manufacturers. The operating temperature window is between 500°F and 1,250°F.

Table 5 - CO Oxidation Catalyst

Catalyst Properties	Specifications
Manufacturer	Englehard
Model	Camet
Catalyst Type	Pt on Al single layer metal monolith
Catalyst Life	20,000 hours or 5 years
Space Velocity	125,000 hr^{-1}
Volume	200 ft^3
CO removal efficiency	90%
CO at stack outlet	6.0 ppmvd at 15% O_2
Exhaust gas velocity	24 ft/s

<u>Aqueous Ammonia Storage Tank (A/N 451185)</u>
The ammonia will be transported to the site in aqueous form and will have a maximum concentration of 19% by weight. The ammonia will be stored in a specially designated tank with a capacity of 16,000 U.S. gallons with a maximum design pressure of 25 psig, and will be constructed to ASME Section VIII specifications. A vapor return line will be used during receiving operations to control filling losses.

<u>Heated Ammonia Vaporization Skid</u>
The ammonia vaporization skids will be used to vaporize the 19% aqueous ammonia so that it can be transferred to the ammonia injection grids. The ammonia vaporization equipment will be shop-assembled and skid mounted for easy field installation. During cold start-up of the turbine, it will take some time (~10 minutes) before the ammonia injection chamber is hot enough to heat the ammonia for injection. Therefore, each ammonia injection chamber is equipped with an electric pre-heater unit which can be initiated prior to the cold start-ups to ensure that the ammonia is adequately heated prior to injection. The ammonia vaporization skids are typically configured with two dilution air fans (one operating and one spare) and two pre-heater elements (one operating and one spare) housed in a common heater box. In addition, the aqueous ammonia is typically atomized in the ammonia injection chamber and is then fed to the ammonia distribution header.

Ammonia Distribution Header

A carbon steel ammonia distribution header will be used to receive the hot ammonia/air mixture from the ammonia vaporization skid and deliver it evenly to the ammonia injection grid piping. Typically, the injection grid supply piping is equipped with manual butterfly valves and flow instrumentation used for adequate balancing of ammonia flow.

Performance Warranties

Performance warranties for the CO/oxidation and SCR catalysts have been included with the application package and are part of the engineering file. According to the performance warranty[5] for the CO/oxidation catalyst, it will be able to achieve approximately 90% CO reduction from inlet levels of CO. The SCR catalyst will be able to achieve approximately 90% reduction efficiency from inlet levels of NOx and the maximum ammonia slip is warranted to not exceed 5.0 ppmvd at 15% O_2. The table below shows the warranted emissions for NOx, CO, VOC and NH_3 slip.

Table 6 - Warranted Emissions for APC System

Pollutant	Warranted Emissions
Outlet NOx emissions	2.5 ppmv at 15% O_2, dry basis
Outlet CO emissions	6.0 ppmv at 15% O_2, dry basis
Outlet VOC emissions	2.0 ppmv at 15% O_2, dry basis
Ammonia Slip	5.0 ppmv at 15% O_2, dry basis

Cooling Tower System

A 5-cell cooling tower will be included in the proposed design to provide for the gas turbine auxiliary cooling requirements. Two 50% capacity circulating water pumps will provide water to cool three closed-cooling water heat exchangers. The circulating water rate will be 35,500 gallons per minute (GPM). The heat exchangers are each rated at 33% capacity. The closed-cooling water heat exchangers will provide high-quality cooling water to a GE provided pump skid for each CTG. The pump skid will then provide cooling water to the CT compressor intercooler and to the lubrication system. Drift is water entrained by and carried with the air as unevaporated fine droplets. PM_{10} matter is released from a cooling tower through drift. Any solids that are dissolved in the cooling water will be carried out of the tower with the water droplets that are entrained in the air. The water droplet will ultimately evaporate and leave the dissolved solid as PM_{10}. The rate of PM_{10} that is discharged to the atmosphere depends significantly on the drift factor for the cooling tower. The drift factor is the percentage of coolant that leaves through drift with respect to the total flow rate of coolant through the tower. Typical drift rates based on the age of the cooling tower are shown in Table 7 below.

Table 7 - Typical Drift Rates Based on the Age of the Cooling Tower

Year of Construction	Drift Rate as a Percentage of Circulating Water Flow Rate
1970s	0.01%
Early 1980's	0.008%
Mid 1980's	0.005%
1990's	0.002%
2000	0.001%
Current Technology	0.0005%

[5] The performance warranty does not explicitly state an expected conversion efficiency for VOC. However, based on experience with similar turbines, it is expected that at least a 50% reduction efficiency for VOC can result such that VOC emissions at the catalyst outlet can be expected to meet 2.0 ppmvd @ 15% O_2. Therefore, uncontrolled VOC emissions are assumed to be 4.0 ppmvd at 15% O_2, dry basis.

In keeping with current technology, maximum drift loss will be limited to 0.0005% of the circulating water flow. The following table lists the specifications for the cooling tower.

Table 8 - Cooling Tower Specifications

Cooling Tower Parameters	Specifications
Manufacturer	Marley
Number of Cells	5
Exhaust Fan Diameter (ft)	22
Exhaust Flow per Cell (ACFM)	860,100
Circulating Water Rate (GPM)	35,500
Circulating Water Rate (MMlb/hr)	17.74
Fan Exit Height (ft AGL)	39.09

Emergency Fire Pump Engine (A/N 450908)

The fire pump engine will be a diesel fueled Clarke unit, model no. JW6H-UF50. It has a power rating of 340 bhp at 2,100 rpm. The specifications are listed in the table below.

Table 9 - Emergency Fire Pump Specifications

Emergency Fire Pump Parameters	Specifications
Manufacturer	Clarke
Power output	340 bhp at 2,100 rpm
Fuel Consumption	16.0 gal/hr
Exhaust temperature	744°F
Exhaust flow	2,066 ACFM
Stack height	40 ft
Stack diameter	5 in

CRITERIA POLLUTANT EMISSIONS

The total emissions from the power plant will include the summation of all five CTGs, the emergency fire pump engine, and the PM_{10} emissions from the cooling tower. The emissions from the gas turbines are based on the following formula and assumptions:

$$EF(lb/MMBTU) = ppmvd \times MW \times \left(\frac{1}{SMV}\right)\left(\frac{20.9}{5.9}\right) \times F_d$$

where,

ppmvd = Uncontrolled (or controlled) concentration at 15% O_2, dry basis
MW = Molecular weight, lb/lb-mol
SMV = Specific molar volume at 68°F = 385.3 dscf/lb-mol
F_d = Dry oxygen f-factor for natural gas at 68°F = 8,710 dscf/MMBTU

Assumptions:
1. Emissions are based on the worst case operating scenario
2. PM_{10} emissions are based on 0.0067 lb/MMBTU
3. SO_2 to SO_3 conversion in APC equipment is accounted for in the PM_{10} AP-42 emission factor
4. SOx emissions are based on 0.25 grains/100 scf
5. 30-Day Averages are based on 463 hours/month of operation
6. Emissions are based on total fuel consumption rather than total hours of operation

The applicant has identified fifteen possible operating scenarios. The fifteen scenarios are listed as operating conditions (OC) 100 through 114 in Section 5 of the applicant's submittal and are summarized in the table below:

Table 10 - Operating Scenarios

	Ambient Temp °F	H_2O Injection, lb/hr	Relative Humidity (%)	Intercooler (on/off)	Compressor Inlet Temp °F
OC100	30	35,385 (100%)	60	On	30
OC101	30	24,795 (70%)	60	On	30
OC102	30	15,760 (45%)	60	On	30
OC103	59	32,449 (92%)	60	On	53
OC104	59	22,235 (63%)	60	On	53
OC105	59	13,945 (39%)	60	On	53
OC106	84	28,325 (80%)	53	On	73
OC107	84	18,872 (53%)	53	On	73
OC108	84	11,031 (31%)	53	On	73
OC109	90	28,389 (80%)	37	On	73
OC110	90	18,917 (53%)	37	On	73
OC111	90	11,074 (31%)	37	On	73
OC112	110	28,408 (80%)	10	On	74
OC113	110	18,932 (54%)	10	On	74
OC114	110	11,527 (33%)	10	On	74

Detail of Operating Conditions

Analysis of the applicant's operating scenarios reveals that GE ran the tests while varying the water injection rate, and compressor inlet temperature. Ambient temperature was allowed to vary from a minimum of 30ºF to a maximum of 110ºF. Note from the table above that for each ambient temperature, the load was varied between maximum (100%), average (75%), and minimum (50%) loads. The top five cases where fuel flow to the CTGs is the greatest (and therefore yielding the highest emissions) are shown in the table below.

Table 11 - Worst Case Operating Scenario

	Top 5 Operating Conditions				
	100	103	106	109	112
Ambient Temperature, °F	30	59	84	90	110
Ambient Pressure, psia	13.937	13.937	13.937	13.937	13.937
Fuel Consumption, MMBTU/hr	803.3	791.6	748.4	749.5	749.6
Fuel Consumption, lb/hr	38,941	38,373	36,277	36,330	36,337
Exhaust Temperature, °F	761.1	781.6	796.6	796.2	796.1
Load, MW	103.8	101.3	94.2	94.4	94.4
Water Injection (on/off)	On	On	On	On	On
Water Injection, lb/hr	35,385	32,449	28,325	28,389	28,408
Intercooler (on/off)	On	On	On	On	On

Of the top five cases, the worst case scenario occurs during periods of maximum fuel consumption (803.3 MMBTU/hr) at full load (103.8 MW), low ambient temperature (30°F), with water injection in full use, and the intercooler in operation, as identified in the table above by operating condition no. 100. Therefore, to address the worst case scenario, the facility's NSR emissions will be based on the parameters listed in operating condition no. 100.

There are essentially four modes of operation for the CTGs. Emissions from the four operating modes are distinctly different and must be calculated independently. The following table gives more detail of the four operating modes.

Table 12 - Operating Modes of the CTGs

Mode	Description
Commissioning	The process of fine-tuning each of the CTGs. Facility follows a systematic approach to optimize performance of each of the CTGs and the associated control equipment. Emissions are expected to be greater during commissioning than during normal operation. This mode affects only the initial year of operation.
Start-up	The applicant has indicated that there will be up to two start-ups per day for each CTG, with each start-up lasting 35 minutes. Start up emissions are higher due to the fact that the control equipment has not reached optimal temperature to begin the chemical reactions needed to convert NOx to elemental nitrogen and water.
Normal Operation	Normal operation occurs after the CTGs and the control equipment are working optimally, at their designated levels, i.e. NOx emissions are controlled to 2.5 ppmvd at 15% O_2, CO emissions to 6.0 ppmv at 15% O_2, and VOC to 2.0 ppmvd at 15% O_2. Emissions may vary due to ambient conditions.
Shutdown	Shutdown occurs at the initiation of the turbine shutdown sequence and ends with the cessation of CTG firing, and will last approximately 11 minutes thereafter. Typically, the shutdown process will emit less than the start-up process but may emit slightly greater than during normal operation because both H_2O injection into the CTGs and NH_3 injection into the SCR reactor have ceased operation

Commissioning Period

Gas turbine commissioning consists of zero load, partial load and full load testing performed immediately after construction for the purposes of optimizing turbomachinery, gas turbine combustors, and optimizing and testing of the SCR/CO catalysts. Several parameters such as water injection rate and degree of SCR and CO control may be varied simultaneously during testing at the discretion of the applicant. Emissions during the commissioning year (usually the first year of operation) may be higher than those during a non-commissioning year due to the fact that the combustors may not be optimally tuned and the SCR/CO catalysts may be only partially operational or not operational at all. The applicant has allocated up to 134 hours of commissioning for each of the 5 CTGs and has further stated that all commissioning will be accomplished within the 9 months prior to initial operation. The commissioning schedule will comprise 6 phases in which the CTGs will be operated at zero, minimum, average and maximum loads while varying the water injection rates and the degree of SCR reactor and CO catalyst control. There will be some cases where the 5 CTGs will be run simultaneously during the commissioning period, and some cases where only one unit may be tested at a time. It will be assumed that the commissioning of the units will be simultaneous to address the worst case scenario. The table below shows the applicant's proposed commissioning schedule along with the cumulative emissions for each of the 5 CTGs during the commissioning period.

Table 13 - Proposed Commissioning Schedule

Commissioning Phase	1	2	3	4	5	6	Totals
Water Injection (% operation)	0	0	50%	100%	100%	100%	
SCR Reactor (% operation)	0	0	0	0	50%	100%	
CO Catalyst (% operation)	0	0	0	0	100%	100%	
Hours per phase	20	14	24	12	24	40	134
Average Load (%)	0%	5%	50%	100%	75%	100%	
NOx (lb/hr)	91	99	175	81	35	8.1	
CO (lb/hr)	55	60	168	255	9	12	
VOC (lb/hr)	2	2	3	5	4	2	
PM_{10} (lb/hr)	1	1	3	6	5	6	
SOx (lb/hr)	0.051	0.061	0.170	0.306	0.238	0.306	
HHV (MMBTU/hr)	150	180	500	900.5	700	900.5	
NOx (lb/mmscf)	641	581	370	95	53	9	
CO (lb/mmscf)	387	352	355	299	14	14	
VOC (lb/mmscf)	14	12	6	6	6	2	
PM_{10} (lb/MMBTU)	0.0067	0.0067	0.0067	0.0067	0.0067	0.0067	
SOx (lb/MMBTU)	0.00068	0.00068	0.00068	0.00068	0.00068	0.00068	
Total NOx lbs, (5 units)	9,100	6,930	21,000	4,860	4,200	1,620	**47,710**
Total CO lbs, (5 units)	5,500	4,200	20,160	15,300	1,080	2,400	**48,640**
Total VOC lbs, (5 units)	200	140	360	300	480	400	**1,880**
Total PM_{10} lbs, (5 units)	100	70	360	360	600	1,200	**2,690**
Total SOx lbs, (5 units)	10.2	12.2	34.0	61.2	47.6	61.2	**226.4**

Start-up / Shutdown of CTGs

The applicant has stated that there will be 350 start-ups and 350 shutdowns per year, with up to 2 start ups per day, with the balance of 2,768 hours left for commissioning and normal operations. According to the applicant, each start-up event is expected to last 35 minutes. During start-up operations, the turbine is assumed to operate at elevated NOx and CO average concentration rates due to the phased-in effectiveness of the SCR reactor and CO oxidation catalysts. Start-ups begin with each turbine's initial firing and continue until each unit complies with the permitted emission concentration limits.

NOx levels are in the 50-100 ppmvd range from the first 3-8 minutes of start-up. Water is injected during the 8^{th} minute of start-up and 25 ppmvd at 15% O_2 is achieved by minute 10 when the unit reaches full load. NOx emissions are further reduced from 25 ppmvd to 2.5 ppmvd over a 30-60 minute period after the CTG achieves full load. CO emissions are assumed to be in the 100-500 ppmvd range for minutes 3 through 10 of start-up. At full load (minute 10), the CO emissions are approximately 100 ppmvd. CO emissions are further reduced from 100 ppmvd to 6 ppmvd over a 30-60 minute period after the CTG achieves full load. GE has provided start-up estimates for the five CTGs and these numbers are included in Appendix A. Shutdowns begin with the initiation of the turbine shutdown sequence and end with the cessation of turbine firing. According to the applicant, each shutdown will last eleven minutes. Upon initiation of the shutdown process, ammonia and water injection will be discontinued. Normal operating emission rates are assumed to occur during the preceding 48 minutes of the shutdown period. GE has provided shutdown estimates for the five CTGs and these numbers are included in Appendix A.

Normal Operations

The emissions during normal operations are assumed to be fully controlled to Best Available Control Technology (BACT) levels, and exclude emissions due to commissioning, start up and shutdown periods, which are not subject to BACT levels. Hourly, monthly, and annual emissions as well as the 30-day averages are calculated and shown in Appendices A through C. The emission calculations for the emergency fire pump and cooling tower are contained in Appendices D and E.

Emissions During A Commissioning Year

The tables below show the cumulative emissions during a commissioning year from all 5 gas turbines which includes commissioning, start-up, shutdown and normal operation, as well as the emissions from the emergency fire pump which is assumed to operate for the designated maximum of 199 hours per year, and the PM_{10} emissions from the 5-cell cooling tower.

Mass Emission Rates, lb/hr (Commissioning Year)

	Emissions, lb/hr					
LMS100PA CTG	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	41.05	60.00	8.55	3.03	30.00	30.35
Start up	51.20	102.00	14.05	3.03	30.00	N/A
Shutdown	55.00	140.00	15.00	3.03	30.00	N/A
Commissioning	356.04	362.99	14.02	1.69	20.07	N/A
Emergency Fire Pump	10.54	0.202	0.112	0.0041	0.059	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	0.443	N/A
TOTALS	**514.73**	**665.19**	**51.73**	**10.78**	**110.57**	**30.05**

Mass Emission Rates, lb/month (Commissioning Year)

	Emissions, lb/month					
LMS100PA CTG	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	15,105.00	22,080.00	3,146.40	1115.00	11,040.00	11,168.80
Start up	2,084.00	4,080.00	562.00	120.00	1,200.00	N/A
Shutdown	2,200.00	5,600.00	600.00	120.00	1,200.00	N/A
Commissioning	5,340.00	5,445.00	210.75	25.50	300.00	N/A
Emergency Fire Pump	174.79	3.35	1.86	0.07	1.12	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	128.30	N/A
TOTALS	**24,903.79**	**37,208.35**	**4,521.01**	**1,383.07**	**13,869.42**	**11,168.80**

Mass Emission Rates, lb/year (Commissioning Year)

	Emissions, lb/year					
LMS100PA CTG	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	108,125.00	158,040.00	22,520.00	7,980.00	79,020.00	79,939.42
Start up	18,235.00	35,700.00	4,920.00	1,060.00	10,500.00	N/A
Shutdown	19,250.00	49,000.00	5,250.00	1,060.00	10.500.00	N/A
Commissioning	47,710.00	48,640.00	1,880.00	228.00	2,690.00	N/A
Emergency Fire Pump	2,097.46	40.24	22.35	0.82	13.41	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	1,539.60	N/A
TOTALS	**195,417.46**	**291,420.24**	**34,592.35**	**10,327.82**	**104,263.01**	**79,939.42**

Emissions During A Non-Commissioning Year

The tables below show the cumulative emissions during a non-commissioning year from all 5 gas turbines which includes, start-up, shutdown and normal operation, as well as the emissions from the emergency fire pump which is assumed to operate for the designated maximum of 199 hours per year, and the PM_{10} emissions form the 5-cell cooling tower.

Mass Emission Rates, lb/hr (Non-Commissioning Year)

	Emissions, lb/hr					
LMS100PA CTG	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	41.05	60.00	8.55	3.03	30.00	30.35
Start up	51.20	102.00	14.05	3.03	30.00	N/A
Shutdown	55.00	140.00	15.00	3.03	30.00	N/A
Emergency Fire Pump	10.54	0.202	0.112	0.0041	0.067	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	0.443	N/A
TOTALS	**158.69**	**302.20**	**37.71**	**9.09**	**90.51**	**30.05**

Mass Emission Rates, lb/month (Non-Commissioning Year)

	Emissions, lb/month					
LMS100PA CTG	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	15,720.00	22,980.00	3,275.00	1,161.49	11,490.00	11,625.29
Start up	2,084.00	4,080.00	562.00	121.20	1,200.00	N/A
Shutdown	2,200.00	5,600.00	600.00	121.20	1,200.00	N/A
Emergency Fire Pump	174.79	3.35	1.86	0.07	1.12	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	128.30	N/A
TOTALS	**20,178.79**	**32,663.35**	**4,438.86**	**1,403.96**	**14,019.42**	**11,625.29**

Mass Emission Rates, lb/year (Non-Commissioning Year)

	Emissions, lb/year					
LMS100PA CTG	NOx	CO	VOC	SO_2	PM_{10}	NH_3
Normal Operations	113,626.40	166,080.00	23,666.40	8,387.00	83,040.00	83,945.03
Start up	18,235.00	35,700.00	4,920.00	1,060.00	10,500.00	N/A
Shutdown	19,250.00	49,000.00	5,250.00	1,060.00	10,500.00	N/A
Emergency Fire Pump	2,097.46	40.24	22.35	0.82	13.41	N/A
5-Cell Cooling Tower	N/A	N/A	N/A	N/A	1,539.60	N/A
TOTALS	**153,208.86**	**250,820.24**	**33,858.75**	**10,507.82**	**105,593.01**	**83,945.03**

30-Day Averages

The 30 Day Average emissions are calculated in Appendix B for both a commissioning and non-commissioning year for the worst case operating scenario. The worst case operating scenario was defined as OC100 in Table 10 above. The values in the tables below are the cumulative 30 day averages for the entire facility (5 CTGs, the emergency fire pump and the cooling tower).

Cumulative 30-Day Averages, lb/day (Commissioning Year)

	30 Day Average, lb/day				
Five LMS100PA CTGs	NOx[6]	CO	VOC	SOx	PM_{10}
Normal Operations		736	105	37	368
Start up		136	19	4	40
Shutdown		187	20	4	40
Commissioning		181	7	1	10
One Emergency Fire Pump		0	0	0	0
One 5-Cell Cooling Tower		N/A	N/A	N/A	(4)[8]
TOTALS		**1,240**	**151**	**46**	**458**

Cumulative 30-Day Averages, lb/day (Non-Commissioning Year)

	30 Day Average, lb/day				
Five LMS100PA CTGs	NOx[6]	CO	VOC	SOx	PM_{10}
Normal Operations		766	109	37	383
Start up		136	19	4	40
Shutdown		187	20	4	40
One Emergency Fire Pump[7]		0	0	0	0
One 5 Cell Cooling Tower		N/A	N/A	N/A	(4)[8]
TOTALS		**1,089**	**148**	45	**463**

The following is a comparison of the <u>cumulative</u> 30-day averages for the entire facility (5-LMS100 PA gas turbines, 1-emergency fire pump, and 1-cooling tower) for both a commissioning year and a non-commissioning year. The <u>maximum</u> 30-day averages for each pollutant, shown in bold.

	NOx[6]	CO	VOC	SOx	PM_{10}
Facility 30 Day Average (Commissioning Year)		**1,240**	**151**	**46**	458
Facility 30 Day Average (Non-Commissioning Year)		1,089	148	45	**463**

The following table shows the 30-day averages from <u>one</u> individual LMS100PA gas turbine for both a commissioning year and a non-commissioning year. The <u>maximum</u> 30-day averages for each pollutant are shown in bold.

	NOx[6]	CO	VOC	SOx	PM_{10}
30 Day Average (Commissioning Year)		**248**	**30**	**9**	92
30 Day Average (Non-Commissioning Year)		218	30	9	**93**

[6] WCEP has elected to enter RECLAIM. As such, RECLAIM Trading Credits (RTC) will be used to satisfy the NOx offsetting requirements of Rule 2005, and therefore the 30-Day Averages for NOx need not be calculated

[7] The emergency fire pump is exempt from offsets (and modeling) under Rule 1304(a)(4)-Emergency Equipment if operated < 200 hr/yr

[8] The cooling tower is exempt from requiring a permit under Rule 219(e)(3) and consequently it is exempt from NSR. Therefore, offsets are not required for the cooling tower.

PROHIBITORY RULE EVALUATION

RULE 212-Standards for Approving Permits

Rule 212 requires that a person shall not build, erect, install, alter, or replace any equipment, the use of which may cause the issuance of air contaminants or the use of which may eliminate, reduce, or control the issuance of air contaminants without first obtaining written authorization for such construction from the Executive Officer. Rule 212(c) states that a project requires written notification if there is an emission increase for ANY criteria pollutant in excess of the daily maximums specified in Rule 212(g), if the equipment is located within 1,000 feet of the outer boundary of a school, or if the MICR is equal to or greater than one in a million (1EE-6) during a lifetime (70 years) for facilities with more than one permitted unit, source under Regulation XX, or equipment under Regulation XXX, unless the applicant demonstrates to the satisfaction of the Executive Officer that the total facility-wide maximum individual cancer risk is below ten in a million (10EE-6) using the risk assessment procedures and toxic air contaminants specified under Rule 1402; or, ten in a million (10EE-6) during a lifetime (70 years) for facilities with a single permitted unit, source under Regulation XX, or equipment under Regulation XXX. The total facility wide residential MICR is expected to be less than 1EE-6. However, since the emissions of criteria pollutants for the facility exceed the thresholds in Rule 212(g), a public notice is required in accordance with the requirements of Rule 212. A public notice will be issued followed by a 30-day public comment period prior to issuance of a permit.

FACILITY / EQUIPMENT AND SCHOOL LOCATIONS

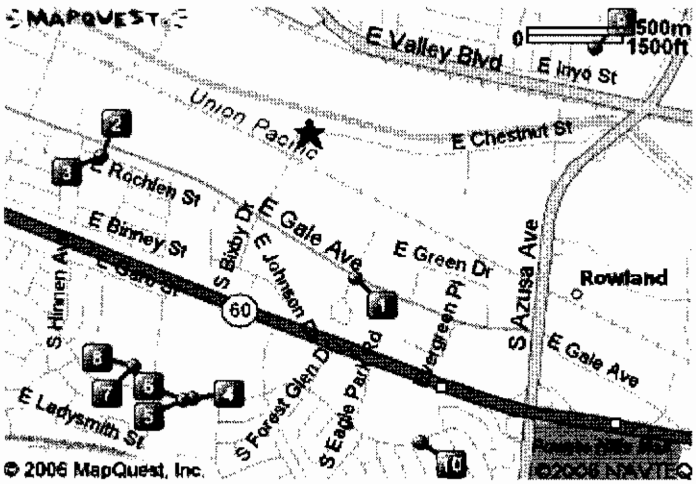
This proposed project is located at 911 Bixby Drive, City of Industry. Schools located nearest to the facility are at least a minimum of 0.41 miles away from the proposed project site as measured by the Mapquest program found at http://www.google.com.

As an alternate means of determining the sensitive receptor distance from the proposed site, latitude/longitude coordinates were collected at the proposed site as well as the closest sensitive receptors using a digital camera equipped with a GPS receiver. The receptor coordinates were then converted to distances, measured in feet, from the proposed site. The following table shows the distance from WCEP to each sensitive receptor as measured by (1) Mapquest and (2) using GPS coordinates (fenceline-to-fenceline)

Name of School	Address	Mapquest Distance Miles (feet)	GPS Distance (feet)
1. Premier Language Center	1200 John Reed Ct, City of Industry	0.41 (2,165)	2,586
2. Glenelder Elementary School	16234 Folger St, Hacienda Heights	0.60 (3,168)	2,997
3. Hacienda La Puente Unified	16234 Folger St Hacienda Heights	0.60 (3,168)	2,997
4. Wilson High School	16455 Wedgeworth Dr Hacienda Heights	0.80 (4,224)	2,897
5.Bixby Elementary School	16446 Wedgeworth Dr Hacienda Heights	0.81 (4,277)	Not Measured
6. Hacienda La Puente Unified	16446 Wedgeworth Dr Hacienda Heights	0.81 (4,277)	Not Measured
7. Cedarlane Middle School	16333 Cedarlane Dr Hacienda Heights	0.82 (4,330)	3,277
8. Hacienda La Puente Unified	16333 Cedarlane Dr Hacienda Heights	0.82 (4,330)	3,277
9. Hurley Elementary School	535 Dora Guzman Ave La Puente	0.85 (4,480)	Not Measured
10. Wedgeworth Elementary School	16949 Wedgeworth Dr Hacienda Heights	0.90 (4,752)	3,796

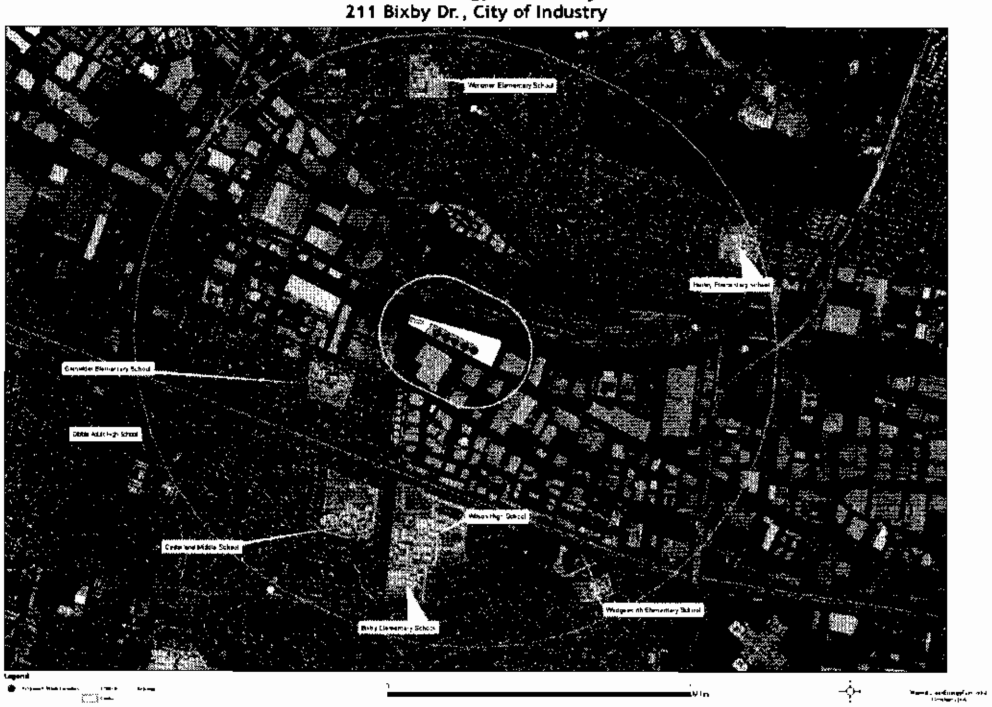
Each of the sensitive receptors are located at distances greater than 1,000 feet from the proposed WCEP site, as verified by both Mapquest and GPS coordinates.

The map below is a graphical representation of the surrounding vicinity of the proposed WCEP site, which includes the locations of the sensitive receptors depicted in purple. The proposed project site is therefore not located within 1,000 feet of the outer boundary of a school.



Below is an aerial shot of the surrounding vicinity of the proposed Walnut Creek Energy Project. The inner circle depicts the area within 1,000 feet from the proposed site. The larger circle represents an area within 1 mile of the proposed site.

Walnut Creek Energy Park Project
211 Bixby Dr., City of Industry



RULE 401-Visible Emissions
This rule limits visible emissions to an opacity of less than 20 percent (Ringlemann No.1), as published by the United States Bureau of Mines. It is unlikely, with the use of the SCR /CO catalyst configuration that there will be visible emissions. However, in the unlikely event that visible emissions do occur, anything greater than 20 percent opacity is not expected to last for greater than 3 minutes. During normal operation, no visible emissions are expected. Therefore, based on the above and on experience with other CTGs, compliance with this rule is expected.

RULE 402-Nuisance
This rule requires that a person not discharge from any source whatsoever such quantities of air contaminants or other material which cause injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which cause, or have a natural tendency to cause injury or damage to business or property. The new turbine will be operated in a fairly remote (non-residential) area of San Bernardino County and is not expected to create a public nuisance based on experience with identical CTGs. Therefore, compliance with Rule 402 is expected.

RULE 403-Fugitive Dust
The purpose of this rule is to reduce the amount of particulate matter entrained in the ambient air as a result of man-made fugitive dust sources by requiring actions to prevent, reduce, or mitigate fugitive dust emissions. The provisions of this rule apply to any activity or man-made condition capable of generating fugitive dust. This rule prohibits emissions of fugitive dust beyond the property line of the emission source. The applicant will be taking steps to prevent and/or reduce or mitigate fugitive dust emissions from the project site. Such measures include covering loose material on haul vehicles, watering, and using chemical stabilizers when necessary. The installation and operation of the CTGs is expected to comply with this rule.

RULE 407-Liquid and Gaseous Air Contaminants
This rule limits CO emissions to 2,000 ppmvd and SO_2 emissions to 500 ppmvd, averaged over 15 minutes. For CO, the CTGs will meet the BACT limit of 6.0 ppmvd @ 15% O_2, 1-hr average, and the turbine will be conditioned as such. For SO_2, equipment which complies with Rule 431.1 is exempt from the SO_2 limit in Rule 407. The applicant will be required to comply with Rule 431.1 and thus the SO_2 limit in Rule 407 will not apply.

RULE 409-Combustion Contaminants
This rule restricts the discharge of contaminants from the combustion of fuel to 0.1 grain per cubic foot of gas, calculated to 12% CO_2, averaged over 15 minutes. The equipment is expected to meet this limit based on the calculations shown below:

Estimated exhaust gas	364,419 DSCFM = 21.87 mmscf/hr
Maximum PM10 Emissions	6 lb/hr
Estimated CO2 in exhaust	3%

$$\text{Grain Loading} = \frac{(6\ \text{lb/hr})\ (7000\ \text{gr/lb})}{21.87\text{EE}6\ \text{scf/hr}} \times \frac{12}{3} = 0.00768\ \text{gr/dscf} << 0.1\ \text{gr/dscf}$$

RULE 431.1-Sulfur Content of Gaseous Fuels
WCEP will use pipeline quality natural gas which will comply with the 16 ppmv sulfur limit, calculated as H2S, specified in this rule. WCEP has provided a gas analysis which demonstrates the natural gas has a sulfur content of less than 0.25 gr/100scf, which is equivalent to a sulfur concentration of about 4 ppmv. It is also much less than the 1 gr/100scf limit typical of pipeline quality natural gas. Compliance is expected.

RULE 474-Fuel Burning Equipment-Oxides of Nitrogen
Superseded by NOx RECLAIM.

RULE 475-Electric Power Generating Equipment
This rule applies to power generating equipment rated greater than 10 MW installed after May 7, 1976. Requirements specify that the equipment must comply with a PM_{10} mass emission limit of 11 lb/hr or a PM_{10} concentration limit of 0.01 grains/dscf. Compliance is demonstrated if either the mass emission limit or the concentration limit is met. The PM10 mass emissions from the WCEP turbines is estimated to be 6 lb/hr. The estimated grain loading is less than 0.01 grain/dscf (see calculations under Rule 409 analysis). Therefore, compliance is expected. Compliance will be verified through performance tests.

NEW SOURCE REVIEW (NSR) ANALYSIS

The following section describes the NSR analysis for WCEP. The facility can comply with NSR either by qualifying for various exemptions from or by demonstrating compliance with the following rules. Since WCEP is a new facility, there are no exemptions from any portions of NSR. Therefore each of the following NSR rules will apply. Each piece of equipment at WCEP is evaluated for compliance with the rules in the table below.

Table 14 - Applicable NSR Rules for WCEP

Applicable NSR Rules for Non-RECLAIM Pollutants (CO, VOC, SOx, PM_{10})	Applicable NSR Rules for RECLAIM Pollutants (NOx)
Rule 1303(a)-BACT	Rule 2005(b)(1)(A)-BACT
Rule 1303(b)(1)-Modeling	Rule 2005(b)(1)(B)-Modeling
Rule 1303(b)(2)-Offsets	Rule 2005(b)(2)-Offsets
Rule 1303(b)(3)-Sensitive Zone Requirements	Rule 2005(e)-Trading Zone Restrictions
Rule 1303(b)(4)-Facilitywide Compliance	Rule 2005(g)-Additional Requirements
Rule 1303(b)(5)-Major Polluting Facilities	Rule 2005(h)-Public Notice
Rule 1309.1 - Priority Reserve	Rule 2005(i)-Rule 1401 Compliance
	Rule 2005(j)-Compliance with Fed/State NSR

RULE 1303(a) and Rule 2005(b)(1)(A)-BACT – LMS100 CTGs
These rules state that the Executive Officer shall deny the Permit to Construct for any new source which results in an emission increase of any non-attainment air contaminant, any ozone depleting compound, or ammonia unless the applicant can demonstrate that BACT is employed for the new source. WCEP is a new source with a potential for an increase in emissions and therefore, BACT is required. Each of the LMS100 CTGs proposed for construction by WCEP will be operated on a simple cycle (no steam turbine, HRSG, or secondary electrical generator is associated with simple cycle configurations). As of the date of this evaluation, BACT for simple cycle gas turbines is shown in Table 15 below:

Table 15 - BACT Requirements for Simple Cycle Gas Turbines

NOx	CO	VOC	PM_{10}/SOx	NH_3
3.5 ppmvd, at 15% O_2, 3-hour rolling average	6.0 ppmvd, at 15% O_2, 3-hour rolling average	2.0 ppmvd, at 15% O_2, 3-hour rolling average	Pipeline quality natural gas w/ S content ≤ 1 grain/100 scf	5.0 ppmvd at 15% O_2, 1-hour rolling average

This information was based on a search of the BACT Clearinghouse database and the latest information available is that for a permit issued to El Colton, in January 2003. This unit is an LM6000 Sprint PC model operating on a simple cycle similar to the five CTGs being proposed by WCEP. The unit was permitted at the above emission levels and has been in operation continuously for over one year. Therefore, emission levels in Table 15 are now officially considered BACT for a simple cycle CTG. The applicant has provided a performance warranty which accompanied the initial application package which indicates that each LMS100 operating on a simple cycle can comply with, and for NOx, even exceed the above BACT requirements. The warranty was provided by GE and is included in the engineering file. The applicant is proposing the BACT levels for this project shown in Table 16 below. However, based on a Facility Permit issued to the City of Riverside (A/N 426694) in April 2005 and another Facility Permit issued to Wellhead Power Colton (A/N 439100) in May 2005, each for a simple cycle LM6000 PC Sprint CTG, the averaging times for NOx, CO, and VOC in those permits were reduced from a 3-hour rolling average to a more restrictive 1-hour rolling average. AQMD now considers the more restrictive 1-hour averaging times to be Achieved in Practice and WCEP will therefore be required to comply with the 1-hour averages for NOx, CO, and VOC.

Table 16 - Proposed BACT for WCEP CTGs

NOx	CO	VOC	PM_{10}/SOx	NH_3
2.5 ppmvd, @ 15% O_2, ~~3~~ 1-hour average	6.0 ppmvd, @ 15% O_2, ~~3~~ 1-hour average	2.0 ppmvd, @ 15% O_2, ~~3~~ 1-hour average	PUC quality natural gas w/ S content ≤ 1 grain/100 scf	5.0 ppmvd @ 15% O_2, 1-hour average

A NOx CEMS will be used to verify compliance with the NOx BACT limit and a CO CEMS will be used to verify compliance with the CO BACT limit. The proposed control levels in the table above will exceed the current BACT requirements for NOx and will meet current BACT requirements for all remaining criteria pollutants including NH_3. BACT is satisfied for each of the CTGs.

RULE 1303(a) and Rule 2005(b)(1)(A)-BACT – Emergency Fire Pump

The emergency fire pump is required to employ BACT because the maximum daily emissions from this source are expected to exceed 1 lb/day. As a starting point, the BACT Guidelines found in Part D – Non Major Polluting Facilities specify the following for emergency internal combustion engines:

EPA Tier II Certification Levels Required for Compression Ignition Engines

Rating/size	Deemed Complete After	NMHC+NOx (gm/BHP-hr)	CO (gm/BHP-hr)	PM_{10} (gm/BHP-hr)
50≤BHP<100	6/30/2004	5.6	3.7	0.30
100≤BHP<175	6/30/2003	4.9	3.7	0.22
175≤BHP<300	6/30/2003	4.9	2.6	0.15
300≤BHP<600	**6/6/2003**	**4.8**	**2.6**	**0.15**
600≤BHP<750	6/6/2003	4.8	2.6	0.15
≥750	6/30/2006	4.8	2.6	0.15

The engine falls into the EPA Tier II BACT category highlighted in bold above. However, since WCEP will be Major Polluting Facility as defined in AQMDs BACT Guidelines, BACT for Major Sources applies. Four compression ignition emergency fire pump engines were permitted between 12/13/2000 and 12/9/2003, and the permits were issued to LA County (A/N 418342), East LA College (A/N 417691), Ultramar (A/N 395874), and Pharmavite (A/N 372822). Each of these engines drives an emergency fire pump rated between 110 bhp and 300 bhp. A closer search of AQMD's BACT Clearinghouse for each of these engines reveals no significant advancements in BACT determinations for this category of engine. As for PM_{10}, diesel fired engines are currently employing particulate traps to control PM_{10} emissions. As such, EME will be required to evaluate the technological feasibility of using a particulate trap on the emergency fire pump. In the event that it is not technologically feasible to install a particulate trap to control PM_{10} emissions, the Tier II BACT levels will apply to the emergency fire pump. BACT for SOx emissions for compression ignition emergency fire pumps is diesel fuel with a sulfur content no greater than 0.0015% by weight. A BACT summary for the emergency fire pump is shown below.

Proposed BACT for Emergency Fire Pump (A/N 450943)

Pollutant	EPA Tier II Levels	Proposed BACT	Comply (Yes/No)
NOx+NMHC	4.8 gm/BHP-hr	4.65 gm/BHP-hr	Yes
CO	2.6 gm/BHP-hr	0.45 gm/BHP-hr	Yes
PM_{10}	0.15 gm/BHP-hr	0.09 gm/BHP-hr or particulate trap	Under evaluation for feasibility of particulate trap
SOx	On or after June 1, 2004 the user may only purchase diesel fuel with a sulfur content no greater than 0.0015% by weight (Rule 431.2)		Yes

The manufacturer has indicated that this engine can comply with the Tier II emission levels specified above, and the user will only purchase diesel fuel with a sulfur content of no greater than 0.0015% by weight. The emergency fire pump is expected to comply with BACT.

<u>RULE 1303(a)-BACT – Cooling Tower</u>

Rule 219(e)(3) provides and exemption for water cooling towers and water cooling ponds not used for evaporative cooling of process water or not used for evaporative cooling of water from barometric jets or from barometric condensers and in which no chromium compounds are contained. The 5-cell cooling tower being proposed at WCEP will meet the requirements of Rule 219(e)(3) and is therefore exempt from NSR. BACT therefore does not apply.

<u>RULE 1303(a)-BACT – Ammonia Storage Tank</u>

A pressure relief valve that will be set at no less than 25 psig will control ammonia emissions from the storage tank. In addition, a vapor return line will be used to control ammonia emissions during storage tank filling operations. Based on the above, compliance with BACT requirements is expected.

Based on the above BACT analysis for the entire project, the 5 CTGs and the emergency fire pump will comply with the current BACT requirements found in Regulation XIII (for the non-RECLAIM pollutants) and in Regulation XX (for the RECLAIM pollutants). BACT for all equipment is satisfied.

RULE 1303(b)(1) and Rule 2005(b)(1)(B) - Modeling

The applicant has conducted air dispersion modeling using the EPA Industrial Source Complex Short Term ISCST3 air dispersion model, Version 3. The Tier 4 Health Risk Assessment was conducted in accordance with guidelines set forth by the California Office of Environmental Health Hazard Assessment (OEHHA) and the California Air Resources Board (CARB). The OEHHA/CARB computer program (HARP) was used to determine the health risk assessment. The air dispersion model was run at a single normalized emission rate of 1.0 gram/sec. The applicant has submitted modeling results for both a commissioning and non-commissioning year which considered building downwash effects through the use of the EPA Building Profile Input Program, a program which is compatible with the ISCST3 model. Effects of terrain slope, aspect ratio, plume height, wind speed, wind direction and temperature were also accounted for in the analysis. The data was collected at the AQMD's Walnut monitoring station. The analysis further accounted for flat, simple, intermediate, and complex terrain. Terrain features were taken from 1-second U.S. Geological Survey (USGS) data taken from its Digital Elevation Model (DEM). The DEM data provides terrain elevations with 1-meter vertical resolution and 10-meters horizontal resolution based on a UTM coordinate system. The EPA SCREEN3 model was used to estimate potential impacts due to fumigation. Potential fumigation impacts were estimated for NO_2, CO, and SO_2. Table A-2 shown below is found in Rule 1303 and lists the most stringent ambient air quality standards and allowable change in concentration for each air contaminant. The appropriate averaging times are also listed.

Table A-2
Most Stringent Ambient Air Quality Standard and
Allowable Change in Concentration
For Each Air Contaminant/Averaging Time Combination

Air Contaminant	Averaging Time	Most Stringent Air Quality Standard		Significant Change in Air Quality Concentration	
Nitrogen Dioxide	1-hour	25 pphm	500 μg/m³	1 pphm	20 μg/m³
	Annual	5.3 pphm	100 μg/m³	0.05 pphm	1 μg/m³
Carbon Monoxide	1-hour	20 ppm	23 μg/m³	1 pphm	1.1 μg/m³
	8-hour	9.0 ppm	10 μg/m³	0.45 pphm	0.50 μg/m³
Suspended Particulate Matter <10μm (PM_{10})	24-hour		50 μg/m³		2.5 μg/m³
	AGM[9]		30 μg/m³		1 μg/m³
Sulfate	24-hour		25 μg/m³		1 μg/m³

The applicant is required under Rule 1303(b)(1) to demonstrate compliance with one of the following requirements:

(a) The most stringent air quality standard shown in Table A-2 above, or
(b) The significant change in air quality concentration standards shown in Table A-2 above, if the most stringent air quality standards are exceeded

The applicant has submitted the following modeled maximum project impacts for SVEP. The numbers in the table below are cumulative for the entire facility.

[9] AGM is the acronym for Annual Geometric Mean

Maximum Project Impacts for WCEP

Pollutant	Averaging Time	Max Facility Impact (μg/m³)	Background (μg/m³)	Total Impact (μg/m³)	Most Stringent Standard (μg/m³)	Comply (Yes/No)
NOx	1-hour	165.92	297	462.90	470	Yes
	Annual	0.825	67.9	68.73	100	Yes
SO_2	1-hour	2.71	52.4	55.11	650	Yes
	3-hour	2.56	52.4	54.96	1,300	Yes
	24-hour	0.856	23.5	24.36	109	Yes
	Annual	0.056	8	8.056	80	Yes
CO	1-hour	117.44	12,571	12,688.4	23,000	Yes
	8-hour	40.29	4,989	5,029.3	10,000	Yes
PM_{10}	24-hour	6.77	164	170.8	50	No
	AGM	0.573	58.1	58.7	30	No

As can be seen from the table above, on a cumulative basis, both the 24-hour and AGM air quality standards for PM_{10} will be exceeded. Therefore, the applicant will be required to show compliance with the significant change in air quality standards for PM_{10}. The applicant has submitted PM_{10} concentrations from each individual piece of equipment (shown in the table below) and has listed the concentrations separately so as to indicate that on an individual basis, each turbine on its own can demonstrate compliance with the Rule 1303 significance thresholds shown in Table A-2 above, for both the 24-hour and the AGM averaging periods.

Significance Modeling for SVEP, (μg/m³)

Equipment	24-hour PM_{10} Concentration	24 hour PM10 Significance Level	Annual PM10 Concentration	Annual PM10 Significance Level	Comply (Yes/No)
Turbine No. 1	1.435	2.5	0.119	1	Yes
Turbine No. 2	1.441	2.5	0.116	1	Yes
Turbine No. 3	1.649	2.5	0.113	1	Yes
Turbine No. 4	1.601	2.5	0.107	1	Yes
Turbine No. 5	1.349	2.5	0.101	1	Yes
Fire Pump	0.014	2.5	0.001	1	Yes

AQMD modeling staff reviewed the applicant's analyses for both air quality modeling and health risk assessment (HRA). Modeling staff provided their comments in a memorandum from Ms. Jill Whynot to Mr. Mike Mills dated August 30, 2006. A copy of this memorandum is contained in the engineering file. Staff's review of the modeling and HRA analyses concluded that the applicant used EPA ISCST3 model version 02035 along with the appropriate model options in the analysis for NO_2, CO, PM_{10}, and SO_2. The applicant modeled both the cumulative and individual permit unit impacts for the project. The memorandum states that the ISCST3 modeling as performed by the applicant conforms to the District's dispersion modeling requirements. No significant deficiencies in methodology were noted.

RULE 1303(b)(2) and Rule 2005(b)(2)-Offsets – LMS100 PA CTGs

Since WCEP is a new facility with an emissions increase, offsets will be required for all criteria pollutants. WCEP will be included in NOx RECLAIM and as such, NOx increases will be offset with RTCs at a 1.0 to1 ratio. Non-RECLAIM criteria pollutants (CO, VOC, SOx, and PM_{10}) will be offset by either the purchase of Emission Reduction Credits (ERCs) and/or Priority Reserve Credits (PRCs) at a 1.2 to 1 ratio. The facility may elect to offset emission increases using either purchased ERCs or PRCs or any combination thereof as allowed by AQMD Rules and Regulations. The required RTCs for NOx for the first and second years of operation are shown below. The values include start-ups, commissioning (first year only), normal operation, and shutdowns. (The total emissions for the second year excludes commissioning).

Required NOx RTCs

Operating Condition 100	Hours per Year	NOx (lb/hr)	NOx (lb/year) per device	NOx (lb/year) cumulative
CTGs				
Startup	350	12.00	4,200.00	21,000.00
Shutdown	350	10.92	3,822.00	19,110.00
Normal Operation	2,634	8.21	21,625.14	108,125.70
Commissioning	134	71.21	9,542.14	47,710.70
CTG Totals	3,468		39,189.28	195,946.40
Emergency Fire Pump	199	10.54	2,097.46	2,097.46
Total 1st Year Emissions (lb/year)			41,286.74	198,043.86
Offset Ratio			1.00	1.00
1st year RTCs (lb/year)			**41,287**	**198,044**
2nd year RTCs (lb/year)			**31,745**	**150,333**

Table 17 shows the facility-wide 30-day averages for CO, VOC, PM_{10} and SOx for informational purposes only. Offsets are based upon 30-day averages from individual permit units. As mentioned above, WCEP may elect to use both ERCs and PRCs to provide the required offsets, as shown below, however, PRCs are only available for CO, PM_{10}, and SOx, as depicted in the table below. The amounts in Table 18 are required to fully offset the facility increases and satisfy the requirements of Rule 1303(b)(2): Note maximum 30-day average for PM_{10} excludes the emissions from the cooling tower per Rule 219(e)(3).

Table 17 – 30-Day Averages for the Entire Facility, (lb/day)

	NOx	CO	VOC	SOx	PM_{10}
Maximum 30 Day Average		1,240	151	46	453

Table 18 - Required Offsets for Non-RECLAIM Pollutants (per-turbine basis, lb/day)

	NOx	CO	VOC	SOx	PM_{10}
Maximum 30 Day Average		248	30	9	93
ERC Offset Ratio		1.2	1.2	1.2	1.2
PRC Offset Ratio		1.2	N/A	1.2	1.2
Required Offsets if ERCs are chosen		**298**	**36**	**11**	**112**
Required Offsets if PRCs are chosen		**298**	**N/A**	**11**	**112**

The facility's maximum monthly and annual fuel usage (caps) for the simultaneous operation of the 5 CTGs will be 1,966 mmscf and 14,725 mmscf, respectively, based on operating condition 100. The annual fuel cap will be the basis for the facility's PTE. The monthly and annual fuel caps will correspond to 463 hours/month and 3,468 hours/year of operation. These values were selected by WCEP.

The monthly and annual fuel caps for the emergency fire pump are 264 gallons and 3,184 gallons, respectively. The calculations are shown below and a monthly fuel cap will be included on the Facility Permit as a permit condition.

```
Monthly:
CTGFuel= (803.3 MMBTU/hr)*1.11*(1 scf/1,050 BTU)(463 hr/month)(5 CTGs) = 1,966 MMscf/month
ICEFuel= (16.0 gal/hr)*16.5 hr/month = 264 gal/month

Annually:
CTGFuel= (803.3 MMBTU/hr)*1.11*(1 scf/1,050 BTU)(3,468 hr/year)(5 CTGs) = 14,725 MMscf/year
ICEFuel= (16.0 gal/hr)*199 hr/year = 3,184 gal/year
```

Table 19 below shows the total amount of ERC's that EME has purchased as of October 26, 2006. The table consists of one ERC certificate for VOC (certificate no. AQ003679) purchased on October 23, 2006 from Electrofilm Manufacturing Company in the amount of 8 lb/day. Shaded areas in the table indicate that no ERC's for that pollutant have been acquired by EME as of October 26, 2006.

Table 19 – Total Amount of Emission Reduction Credits currently held by EME

Pollutant	ERC Certificate No.	Date of Purchase	Name of Seller	Amount of ERC (lb/day)
VOC	AQ003679	10/23/2006	Electrofilm Manufacturing	8
CO				
PM10				
SOx				

WCEP has indicated that the required amounts of offsets will be provided prior to issuance of the Facility Permit. Compliance with offset requirements of Rules 1303(b)(2) and 2005(b)(2) is expected.

RULES 1303(b)(3)-Sensitive Zone Requirements and 2005(e)-Trading Zone Restrictions
Both rules state that credits must be obtained from the appropriate trading zone. In the case of Rule 1303(b)(3), unless credits are obtained from the Priority Reserve, facilities located in the South Coast Air Basin are subject to the Sensitive Zone requirements specified in Health & Safety Code Section 40410.5. WCEP is located in Zone 2a and is therefore eligible to obtain its ERCs from either Zone 1 or Zone 2a. Similarly in the case of Rule 2005(e), WCEP, because of its location may obtain RTCs from either Zone 1 or Zone 2, at its choosing. Compliance is expected with both rules.

RULE 1303(b)(4)-Facility Compliance
The new facility will comply with all applicable Rules and Regulations of the AQMD.

RULE 1303(b)(5)-Major Polluting Facilities

Rule 1303(b)(5)(A) – Alternative Analysis
The applicant is required to conduct an analysis of alternative sites, sizes, production processes, and environmental control techniques for the WCEP and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project.

EME has performed a comparative evaluation of alternative sites as part of the AFC process and has concluded that the benefits of providing additional electricity and increased employment in the surrounding area will outweigh the environmental and social costs incurred in the construction and operation of the proposed facility.

Rule 1303(b)(5)(B) – Statewide Compliance
EME has certified in the 400-A form that all major sources under its ownership or control in the State of California are in compliance with all federal, state, and local air quality rules and regulations. In addition, EME has submitted an email to the AQMD dated October 19, 2006 stating that "any and all facilities that EME owns or operates in the State of California (including the proposed WCEP) are in compliance or are on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act. Therefore, compliance is expected.

Rule 1303(b)(5)(C) – Protection of Visibility
Modeling is required if the source is within a Class I area and the NOx and PM10 emissions exceed 40 TPY and 15TYP respectively. Since the nearest Class I area is located over 28 miles from the proposed WCEP site, modeling from plume visibility is not required, however, the applicant has provided modeling impact data for the Class I areas as part of the AFC process. Compliance is expected.

Rule 1303(b)(5)(D) – Compliance through CEQA
The California Energy Commission's (CEC) certification process is essentially equivalent to CEQA. Since the applicant is required to receive a certification from the CEC, the applicable CEQA requirements and deficiencies will be addressed. Compliance is expected.

RULE 1309.1-Priority Reserve
This rule requires an electrical generating facility (EGF) to comply with the requirements in R-1309(c): As part of the recent amendments to Rule 1309.1-Priority Reserve, (September 8, 2006), the AQMD Executive Officer committed to hold a public meeting for each project prior to accessing the Priority Reserve. AQMD held a public meeting to inform the public about the specifics of the proposed project. The meeting was held on October 17, 2006. Topics discussed included facility emissions, local impacts on schools, and surrounding area. The requirements and compliance status are summarized in Table 20 below:

Table 20 - Rule 1309.1 Requirements and Compliance Determination

REQUIREMENTS	COMPLIANCE (Yes/No)
Rule 1309.1(c)(1) - Permit condition requiring facility to comply with BARCT for pollutants received from Priority Reserve for all existing sources prior to operation of any new sources	**(YES)** Since there are no existing sources at this facility, BARCT is not applicable and the new equipment will be constructed using BACT for simple cycle power plants. These emission limits the lowest levels achieved in practice under federal LAER. Compliance is expected
Rule 1309.1(c)(2) - The applicant must pay a mitigation fee pursuant to subdivision (g)	**(YES)** The applicant will pay this fee for each pollutant upon securing PRCs.

Table 20 - Rule 1309.1 Requirements and Compliance Determination

REQUIREMENTS	COMPLIANCE (Yes/No)
Rule 1309.1(c)(3) - Conducts due diligence effort approved by the Executive Officer to secure ERCs for requested Priority Reserve pollutants	**(PENDING)** The applicant has submitted written correspondence to AQMD (see letter in file dated September 27, 2006 from Latham & Watkins to Mr. Mohsen Nazemi) which indicates the applicant is in the process of attempting to secure ERCs for the requested Priority Reserve pollutants. AQMD has received a letter dated September 27, 2006 which which provided information regarding the progess in securing offsets for WCEP. EME will continue to provide progress reports the ERCs are secured.
Rule 1309.1(c)(4) - Applicant has the new source fully and legally operational at rated capacity within 3 years following AQMD permit to Construct issuance or CEC certification, whichever is later	**(YES)** The applicant is scheduled to have the new facility fully operational at its rated capacity by July 2008.
Rule 1309.1(c)(5) - Applicant must enter into a long-term contract with the State of California to sell at least 50% of the portion of power which it has generated using PRCs	**(YES)** The applicant is a power generator and is engaged in the sale of generated power to end users. Most of the power will be supplied to the state's electrical grid. However, at this time, it is the AQMD's understanding that the State of California is not offering long term contracts for the acquisition of power.
Rule 1309.1(c)(6) - Applicant for an in-Basin EGF must purchase PRCs at an offset ratio of 1.2 -to-1.0	**(YES)** The applicant has proposed to purchase both ERCs and PRC at an offset ration of 1.2-to-1.0.
Rule 1309.1(c)(7) - Applicant for a Downwind Air Basin EGF shall obtain credits at an offset ratio as determined by the downwind air district	**(NOT APPLICABLE)** This facility is located within the South Coast Air Basin (SCAB) and the applicable offset ratio for PRCs in the SCAB is 1.2-to-1.0.
Rule 1309.1(c)(8) - Applicant for Permit to Construct must agree to a permit condition which requires new sources to be fully and legally operational at rated capacity within 3 years. An applicant that is a municipality must have an additional year if the EGF contains a renewable energy component with a rated capacity of at least 50 MW of renewable energy.	**(YES)** The applicant is scheduled to have the new facility fully operational at its rated capacity by July 2008.
BASED ON THE INFORMATION IN THIS TABLE, WCEP CAN COMPLY WITH THE APPLICABLE REQUIREMETS OF RULE 1309.1	

Rule 1401 – New Source Review of Toxic Air Contaminants

This rule specifies limits for maximum individual cancer risk (MICR), acute hazard index (HIA), chronic hazard index (HIC) and cancer burden (CB) from new permit units, relocations, or modifications to existing permits which emit toxic air contaminants. Rule 1401 requirements are summarized as follows:

Table 21 – Rule 1401 Requirements

Parameters and Specifications	Rule 1401 Requirements
MICR, without T-BACT	$\leq 1\times10^{-6}$
MICR, with T-BACT	$\leq 1\times10^{-5}$
Acute Hazard Index	≤ 1.0
Chronic Hazard Index	≤ 1.0
Cancer Burden	≤ 0.5

The applicant performed a Tier 4 health risk assessment using the Hot Spots Analysis and Reporting Program (HARP, version 1.2a). The analysis included an estimate of the MICR for the nearest residential and commercial receptors, the acute and chronic hazard indices for the entire facility. PRA modeling staff reviewed the applicant's methodology and procedures used, and re-ran the HARP model and verified the health risk and hazard indices which were presented by the applicant. PRA staff concluded that each of the health risk values for MICR, HIA and HIC were appropriately estimated (see memorandum in file, dated August 30, 2006 from Ms. Jill Whynot to Mr. Mike Mills). Table 22 below is a summary of the modeled health risk assessment results. The cancer burden is not calculated because the MICR is less than 1×10^{-6} for both residential and commercial receptors.

Table 22 – Rule 1401 Modeled Results

Risk Parameter	Residential	Commercial	Rule 1401 Requirements	Compliance (Yes/No)
MICR	6.23×10^{-7}	1.06×10^{-9}	$\leq 1 \times 10^{-6}$	Yes
HIA	0.0635	0.000879	≤ 1.0	Yes
HIC	0.0124	0.0000156	≤ 1.0	Yes
Receptor UTMs	413480E / 3764940N	413123E / 3763141N		

Table 22 shows that WCEP will comply with the applicable requirements of Rule 1401. The cancer burden is not computed because the highest MICR (in this case, the residential MICR) is less than 1×10^{-6}.

<u>RULE 1470-Requirements for Stationary Diesel-Fueled Internal Combustion and Other Compression Ignition Engines</u>.

Rule 1470 imposes the following requirements on compression ignition engines:

Paragraph (c)(1) requires the use of CARB Diesel fuel. The use of No. 2 diesel fuel will satisfy this requirement. Paragraph (c)(2)(A) imposes operating requirements for engines located within 500 feet from a school. Since the engine is located greater than 500 feet to the nearest school, the requirements of this section are not applicable.

Paragraph (c)(2)(B) allows operation of this device during an impending rotating electric power outage only if:

1. The permit specifically allows this operation
2. The utility company has actually ordered the outage
3. The engine is in a specific location covered by the outage.
4. The engine is operated no more than 30 minutes prior to the outage, and
5. The engine operation is terminated immediately after the outage.

AQMD will require a condition to limit the maintenance and testing to less than 50 hours per year. This engine is expected to meet these requirements.

Paragraph (c)(2)(C) limits hours for maintenance and testing to 50 hours per year for PM_{10} emissions up to 0.15 gm/bhp-hr, and a maximum of 100 hours per year for PM_{10} emissions up to 0.01 gm/bhp-hr. Therefore, the engine will comply with paragraph (c)(2)(C). Also, part (iv) of paragraph (c)(2)(C) requires that the engine meet the standards for off road engines in Title 13, CCR section 2423. This engine will comply with the requirements for off road engines. Therefore, compliance with Rule1470 is expected.

Rule 2005(g) – Additional Requirements
As with Rule 1303(b)(5) for the Non-RECLAIM pollutants, WCEP has addressed the alternative analysis, statewide compliance, protection of visibility, and CEQA compliance requirements of this rule for NOx. These requirements are essentially the same as those found in Rule 1303(b)(5), subparts A through D for non-RECLAIM pollutants, and are summarized below.

Rule 2005(g)(1) – Statewide Compliance
EME has certified in the 400-A form that all major sources under its ownership or control in the State of California are in compliance with all federal, state, and local air quality rules and regulations. In addition, EME has submitted an email to the AQMD dated October 19, 2006 stating that "any and all facilities that EME owns or operates in the State of California (including the proposed WCEP) are in compliance or are on a schedule for compliance with all applicable emission limitations and standards under the Clean Air Act. Therefore, compliance is expected.

Rule 2005(g)(2) – Alternative Analysis
The applicant is required to conduct an analysis of alternative sites, sizes, production processes, environmental control techniques for the WCEP and to demonstrate that the benefits of the proposed project outweigh the environmental and social costs associated with this project. EME has performed a comparative evaluation of alternative sites as part of the AFC process and has concluded that the benefits of providing additional electricity and increased employment in the surrounding area will outweigh the environmental and social costs incurred in the construction and operation of the proposed facility.

Rule 2005(g)(3) – Compliance through CEQA
The California Energy Commission's (CEC) certification process is essentially equivalent to CEQA. Since the applicant is required to receive a certification from the CEC, the applicable CEQA requirements and deficiencies will be addressed. Compliance is expected

Rule 2005(g)(4) – Protection of Visibility
Modeling is required if the source is within a Class I area and the NOx emissions exceed 40 TPY. Since the nearest Class I area is located over 28 miles from the proposed WCEP site, modeling from plume visibility is not required, however, the applicant has provided modeling impact data for the Class I areas as part of the AFC process. Compliance is expected

Rule 2005(h) – Public Notice
WCEP will comply with the requirements for Public Notice found in Rule 212. Therefore compliance with Rule 2005(h) is demonstrated.

Rule 2005(i) – Rule 1401 Compliance.
WCEP will comply with Rule 1401 as demonstrated in the Tier 4 analysis and subsequently reviewed and found to be satisfactory by AQMD modeling staff. Compliance is expected.

Rule 2005(j) – Compliance with State and Federal NSR.
WCEP will comply with the provisions of this rule by having demonstrated compliance with AQMD NSR Regulations XIII and Rule 2005-NSR for RECLAIM.

REGULATION XVII-Prevention of Significant Deterioration
The District Governing Board in its action on February 7, 2003, authorized the Executive Officer, upon withdrawal of the EPA PSD delegation, not to request any further delegation and to allow the EPA to terminate the AQMD's PSD delegation agreement and for EPA to become the permitting agency for PSD sources in the AQMD.

The Board determined that Regulation XVII is inactive upon EPA's withdrawal of delegation and shall remain inactive unless and until the EPA provides the AQMD with new delegation of authority to act either in full or on a Facility/Permit-Specific basis. The delegation was rescinded on March 3, 2003 by EPA.

The District Governing Board in its April 1, 2005 meeting reaffirmed its previous action on February 7, 2003 to relinquish PSD analysis back to federal government and render Regulation XVII inactive unless the District receives new delegation in part or in full from the EPA.

Based on the Governing Board's actions, this rule is ineffective and no analysis is required for any pollutant subject to federal PSD requirement. The AQMD has sent the applicant a notification to contact the EPA directly for applicability of PSD to the proposed project. AQMD sent a letter to the applicant on December 8, 2005 and instructed to contact EPA directly regarding implementation of PSD.

INTERIM PERIOD EMISSION FACTORS
RECLAIM requires a NOx emission factor to be used for reporting emissions during the interim reporting period. The interim period is defined as a period, typically 12 months in duration, when the CEMS has not been certified. During this period, the emissions cannot be accurately quantified, monitored, or verified. The emissions during this period are assumed to be at uncontrolled levels. The interim reporting period can be broken down into the two parts which includes the commissioning period in which an uncontrolled[10] emission rate is assumed, and the remaining period at which controlled rates at BACT are assumed.

Since WCEP will be included in NOx RECLAIM, an interim period emission factor will be determined. Although not a RECLAIM pollutant, a CO emission factor will also be calculated so that the applicant may use it to report emissions during the interim period when the CEMS is not yet certified for CO. In the event CEMS data is not available, NOx, CO, and SOx emissions during the interim period will be calculated using monthly fuel usage and the emission factors derived below. There will be two interim period emission factors calculated for NOx and two interim period emission factors calculated for CO.

[10] The emission factor for the commissioning period is an average for the entire 134 hour period. During this period, the turbines may be uncontrolled, partially controlled, or 100% controlled.

The first factor will be for use during commissioning stage when the CTGs are assumed to be operating at uncontrolled levels and the second factor will be for use after commissioning is complete and the CTGs are assumed to operate at BACT levels. SOx is not affected by the presumed absence of emission controls which occurs during commissioning because the SCR and CO catalyst modules control only NOx and CO emissions and to a lesser degree, VOC. Consequently, SOx emissions are assumed to be equal both during and after commissioning and therefore, only one SOx emission factor for the 12 month interim period will be computed. The specific calculations are shown in Appendix G and the results are shown in the tables below.

Commissioning Period

Pollutants	NOx	CO
Total emissions (lbs)	47,710	48,640
Total Fuel (mmscf)	386.43	386.43
Emission Factor (lb/mmscf)	**123.46**	**125.87**

Remaining Period (Non-Commissioning)

Pollutants	NOx	CO
Total emissions (lbs)	153,736	261,280
Total Fuel (mmscf)	14,156.7	14,156.7
Emission Factor (lb/mmscf)	**10.86**	**18.46**

CALIFORNIA ENVIRONMENTAL QUALITY ACT (CEQA)

The CEC is the lead agency for this project and EME filed an Application for Certification (05-AFC-2) for the project on December 1, 2005. WCEP will be subject to the CEC's 12-month energy facility licensing process which will address public issues and concerns involving zoning, biological resources, water resources, air quality, transmission, public health and safety, and their resolution. The CEC's 12-month licensing process is a certified regulatory program under CEQA and includes several opportunities for public participation. The CEC's license/certification subsumes all requirements of state, local, or regional agencies otherwise required before a new plant is constructed. The CEC coordinates its review of the facility with the federal, state, and local agencies that will be issuing permits to ensure that its certification incorporates the conditions that would be required by these various agencies. The AFC process is the functional equivalent of a traditional CEQA review and will address and resolve issues related to CEQA.

NSPS for Stationary Gas Turbines – 40CFR Part 60 Subpart GG

Subpart GG applies to the subject turbines because the heat input is greater than 10.14 MMBTU/hour (10.7 gigajoules per hour). (The actual rating is $891.67*10^6$ BTU/hr * 1,055 joules/BTU = 940.71 gigajoules/hr). The applicable standards are determined as follows:

For NOx,
STD = 0.0075(14.4/Y) + F
where:

Maximum heat input = 891.67 MMBTU/hr
Maximum net output = 104 MW
STD = allowable NOx emissions in percent volume at 15% O_2, dry basis
Y = manufacturer's rating in KJ/watt-hr
F = 0 for fuel with nitrogen content < 0.015 % weight
0.04 * %N for 0.015 < %N < 0.1

Therefore, Y = 891.67 MMBTU/hr / 104 MW * 1,055 joules/BTU * kJ/1000j = 9.045 KJ/watt-hr
For natural gas, nitrogen < 0.015%w, therefore, F=0

STD = 0.0075(14.4/9.045) + 0 = 119 ppmv NOx
Since the proposed limit of 2.5 ppmv << 119 ppmv, compliance is expected.

For SOx, the limit is a straight 150 ppmv

40CFR Part 72 – Acid Rain Provisions

WCEP is subject to the requirements of the federal Acid Rain program because the electricity generated will be rated at greater than 25 MW. This program is similar to RECLAIM in that facilities are required to cover SO_2 emissions with SO_2 allowances that are similar in concept to RTC's. SO_2 allowances are however, not required in any year when the unit emits less than 1,000 lbs of SO_2. Facilities with insufficient allowances are required to purchase SO_2 credits on the open market. In addition, both NOx and SO_2 emissions will be monitored and reported directly to USEPA. Based on the above, compliance with this rule is expected.

REGULATION XXX – Title V

WCEP is a Title V facility because the cumulative emissions will exceed the Title V major source thresholds and because it is also subject to the federal acid rain provisions. The initial Title V permit will be processed and the required public notice will be sent along with the Rule 212(g) Public Notice, which is also required for this project. EPA is afforded the opportunity to review and comment on the project within a 45-day review period.

OVERALL EVALUATION / RECOMMENDATION(S)

Issue a Facility Permit to Construct with the following permit conditions.

PERMIT CONDITIONS

(LMS100PA CTGs) Devices D1,D7,D13,D19,D25

A63.1 The operator shall limit emission from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
PM_{10}	2,722 LBS IN ANY ONE MONTH
CO	6,772 LBS IN ANY ONE MONTH
SOx	281 LBS IN ANY ONE MONTH
VOC	919 LBS IN ANY ONE MONTH

The operator shall calculate the monthly emissions for VOC, PM10 and SOx using the equation below and the following emission factors: VOC: 2.00 lb/mmcf; PM10: 6.93 lb/mmcf; and SOx: 0.71 lb/mmcf.

Monthly Emissions, lb/month = X (E.F.)

Where X = monthly fuel usage in mmscf/month and E.F. = emission factor indicated above.

Compliance with the CO emission limit shall be verified through valid CEMS data.

The operator shall calculate the emission limit(s) for the purpose of determining compliance with the monthly CO limit in the absence of valid CEMS data by using the above equation and the following emission factor(s):

(A) During the commissioning period and prior to CO catalyst installation - 125.87 lbs CO/mmcf

(B) After installation of the CO catalyst but prior to CO CEMS certification testing - 18.46 lb CO/mmcf. The emission rate shall be recalculated in accordance with Condition D82.1 if the approved CEMS certification test resulted in emission concentration higher than 6 ppmv.

(C) After CO CEMS certification testing - 18.46 lb/CO mmcf. After CO CEMS certification test is approved by the AQMD, the emissions monitored by the CEMS and calculated in accordance with condition 82.1 shall be used to calculate emissions.

For the purposes of this condition, the limit(s) shall be based on the emissions from a single turbine. During commissioning, the CO emissions shall not exceed 7,681 lbs in any one month. During commissioning, the VOC emissions shall not exceed 935 lbs in any one month.

The operator shall provide the AQMD with written notification of the date of initial CO catalyst use within seven (7) days of this event.
[Rule 1303 - Offsets]

A63.2 The operator shall limit emissions from this equipment as follows:

CONTAMINANT	EMISSION LIMIT
PM_{10}	20,392 LBS IN ANY ONE YEAR
CO	52,256 LBS IN ANY ONE YEAR
SOx	2,102 LBS IN ANY ONE YEAR
VOC	7,043 LBS IN ANY ONE YEAR

The operator shall calculate the monthly emissions for VOC, PM10 and SOx using the equation below and the following emission factors: VOC: 2.00 lb/mmcf; PM10: 6.93 lb/mmcf; and SOx: 0.71 lb/mmcf.

Annual Emissions, lb/yr = X (E.F.)

Where X = annual fuel usage, mmscf/yr and E.F. = emission factor indicated above.

Compliance with the CO emission limit shall be verified through valid CEMS data.

The operator shall calculate the emission limit(s) for the purpose of determining compliance with the annual CO limit in the absence of valid CEMS data by using the above equation and the following emission factor(s):

(A) During the commissioning period and prior to CO catalyst installation - 125.87 lbs CO/mmcf

(B) After installation of the CO catalyst but prior to CO CEMS certification testing - 18.46 lb CO/mmcf. The emission rate shall be recalculated in accordance with Condition D82.1 if the approved CEMS certification test resulted in emission concentration higher than 6 ppmv.

(C) After CO CEMS certification testing - 18.46 lb/CO mmcf. After CO CEMS certification test is approved by the AQMD, the emissions monitored by the CEMS and calculated in accordance with condition 82.1 shall be used to calculate emissions.

For the purposes of this condition, the limit(s) shall be based on the emissions from a single turbine. During commissioning, the CO emissions shall not exceed 60,376 lbs in any one year. During commissioning, the VOC emissions shall not exceed 7,191 lbs in any one year.

The operator shall provide the AQMD with written notification of the date of initial CO catalyst use within seven (7) days of this event.
[Rule 1303 - Offsets]

For the purpose of this condition, the yearly emission limit shall be defined as a period of twelve (12) consecutive months determined on a rolling basis with a new 12 month period beginning on the first day of each calendar month.
[Rule 1303 - Offsets]

A99.1 The 2.5 PPM NOx emission limits shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 134 hours. Start-up time shall not exceed 60 minutes for each start-up. Shutdown periods shall not exceed 10 minutes for each shutdown. The turbine shall be limited to a maximum of 350 start-ups per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.
[Rule 2005]

A99.2 The 6.0 PPM CO emission limits shall not apply during turbine commissioning, start-up, and shutdown periods. The commissioning period shall not exceed 134 hours. Start-up time shall not exceed 60 minutes for each start-up. Shutdown periods shall not exceed 10 minutes for each shutdown. The turbine shall be limited to a maximum of 350 start-ups per year. Written records of commissioning, start-ups and shutdowns shall be maintained and made available upon request from the Executive Officer.
[Rule 1303(a) - BACT, Rule 1303(b)(1) - Modeling, Rule 1303(b)(2) - Offsets]

A99.3 The 123.46 LBS/MMCF NOx emission limits shall only apply during the interim reporting period during initial turbine commissioning to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.
[Rule 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen Emissions]

A99.4 The 10.86 LBS/MMCF NOx emission limits shall only apply during the interim reporting period after initial turbine commissioning to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from entry into RECLAIM.
[Rule 2012 - Requirements for Monitoring, Reporting and Recordkeeping for Oxides of Nitrogen Emissions]

A195.1 The 6.0 PPMV CO emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1303(a) - BACT, Rule 1303(b)(1) - Modeling, Rule 1303(b)(2) - Offsets]

A195.2 The 2.5 PPMV NOX emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 2005]

A193.3 The 2.0 ppmv VOC emission limit(s) is averaged over 60 minutes at 15 percent O2, dry.
[Rule 1303(a) - BACT, Rule 1303(b)(1) - Modeling, Rule 1303(b)(2) - Offsets]

A327.1 For the purpose of determining compliance with District Rule 475, combustion contaminants emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.
[Rule 475]

C1.1 The operator shall limit the fuel usage to no more than 393 mmcf in any one calendar month.

For the purpose of this condition, fuel usage shall be defined as the total natural gas usage of a single turbine.

The operator shall maintain records in a manner approved by the District to demonstrate compliance with this condition.
[Rule 1303(b)(2) - Offset]

D12.1 The operator shall install and maintain a(n) flow meter to accurately indicate the fuel usage being supplied to the turbine.

The operator shall also install and maintain a device to continuously record the parameter being measured
[Rule 1303(b)(2) - Offset, Rule 2012]

D29.1 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NOX emissions	District Method 100.1	1 hour	Outlet of the SCR
CO emissions	District Method 100.1	1 hour	Outlet of the SCR
SOX emissions	Approved District method	District approved averaging time	Fuel Sample
VOC emissions	Approved District method	1 hour	Outlet of the SCR
PM10 emissions	Approved District method	District approved averaging time	Outlet of the SCR
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

The test shall be conducted after AQMD approval of the source test protocol, but no later than 180 days after initial start-up. The AQMD shall be notified of the date and time of the test at least 10 days prior to the test.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in MW.

The test shall be conducted in accordance with AQMD approved test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the AQMD before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at maximum, average, and minimum loads.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval except for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines.

Because the VOC BACT level was set using data derived from various source test results, this alternate VOC compliance method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results shall be reported with two significant digits.
[Rule 1303(a)(1) - BACT, Rule 1303(b)(2) - Offset, Rule 2005]

D29.2 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
NH3 emissions	District method 207.1 and 5.3 or EPA method 17	1 hour	Outlet of the SCR

The test shall be conducted and the results submitted to the District within 45 days after the test date. The AQMD shall be notified of the date and time of the test at least 7 days prior to the test.

The test shall be conducted at least quarterly during the first twelve months of operation and at least annually thereafter. The NOx concentration, as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District Method 100.1 measured over a 60 minute averaging time period.

The test shall be conducted to demonstrate compliance with the Rule 1303 BACT concentration limit
[Rule 1303(a)(1) - BACT]

D29.3 The operator shall conduct source test(s) for the pollutant(s) identified below.

Pollutant to be tested	Required Test Method(s)	Averaging Time	Test Location
SOX emissions	Approved District method	District approved averaging time	Fuel Sample
VOC emissions	Approved District method	1 hour	Outlet of the SCR
PM10 emissions	Approved District method	District approved averaging time	Outlet of the SCR

The test shall be conducted at least once every three years.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the tests shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output in MW.

The test shall be conducted in accordance with AQMD approved test protocol. The protocol shall be submitted to the AQMD engineer no later than 45 days before the proposed test date and shall be approved by the AQMD before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the tests, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of Rule 304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at maximum, average, and minimum load.

The test shall be conducted for compliance verification of the BACT VOC 2.0 ppmv limit.

For natural gas fired turbines only, VOC compliance shall be demonstrated as follows: a) Stack gas samples are extracted into Summa canisters maintaining a final canister pressure between 400-500 mm Hg absolute, b) Pressurization of canisters are done with zero gas analyzed/certified to contain less than 0.05 ppmv total hydrocarbon as carbon, and c) Analysis of canisters are per EPA Method TO-12 (with pre concentration) and temperature of canisters when extracting samples for analysis is not below 70 deg F.

The use of this alternative method for VOC compliance determination does not mean that it is more accurate than AQMD Method 25.3, nor does it mean that it may be used in lieu of AQMD Method 25.3 without prior approval except for the determination of compliance with the VOC BACT level of 2.0 ppmv calculated as carbon for natural gas fired turbines.

Because the VOC BACT level was set using data derived from various source test results, this alternate VOC compliance method provides a fair comparison and represents the best sampling and analysis technique for this purpose at this time. The test results shall be reported with two significant digits.
[Rule 1303(a)(1) - BACT, Rule 1303(b)(2) - Offset]

D82.1 The operator shall install and maintain a CEMS to measure the following parameters:

CO concentration in ppmv
Concentrations shall be corrected to 15 percent oxygen on a dry basis
The CEMS shall be installed and operated no later than 90 days after initial start-up of the turbine, and in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD. Within two weeks of the turbine start-up, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be installed and operated to measure CO concentrations over a 15 minute averaging time period.

The CEMS would convert the actual CO concentrations to mass emission rates (lbs/hr) using the equation below and record the hourly emission rates on a continuous basis.

CO Emission Rate, lbs/hr = K Cco Fd[20.9% - %O2 d)][(Qg * HHV)/106], where

K = $7.267 * 10^{-8}$ (lb/scf)/ppm

Cco = Average of four consecutive 15 min. ave. CO concentration, ppm

Fd = 8710 dscf/MMBTU natural gas

$\%O_2$ d = Hourly ave. % by vol. O_2 dry, corresponding to Cco

Qg = Fuel gas usage during the hour, scf/hr

HHV = Gross high heating value of fuel gas, BTU/scf
[Rule 1303(a)(1) - BACT, Rule 218]

D82.2 The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppmv

Concentrations shall be corrected to 15 percent oxygen on a dry basis.
The CEMS shall be installed and operating no later than 90 days after initial start-up of the turbine and shall comply with the requirements of Rule 2012. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within two weeks of the turbine start-up date, the operator shall provide written notification to the District of the exact date of start-up.

The CEMS shall be installed and operating (for BACT purposes only) no later than 90 days after initial start up of the turbine.
[Rule 2005; Rule 2012]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 05-AFC-2 project.
[CEQA]

I296.1 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emission increase.

To comply with this condition, the operator shall prior to the 1st compliance year hold a minimum NOx RTCs of 38,664 lbs/yr. This condition shall apply during the 1st 12 months of operation, commencing with the initial operation of the gas turbine.

To comply with this condition, the operator shall, prior to the beginning of all years subsequent to the 1st compliance year, hold a minimum of 29,122 lbs/yr of NOx RTCs for operation of the gas turbine.

In accordance with Rule 2005(f), unused RTC's may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the 1st compliance year.

This condition shall apply to each turbine individually.
[Rule 2005]

K40.1 The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 60 days after the source test was conducted.
Emission data shall be expressed in terms of concentration (ppmv) corrected to 15 percent oxygen (dry basis), mass rate (lb/hr), and lb/MMCF. In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains/DSCF.
All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).
All moisture concentration shall be expressed in terms of percent corrected to 15 percent oxygen.
Source test results shall also include the oxygen levels in the exhaust, fuel flow rate (CFH), the flue gas temperature, and the generator power output (MW) under which the test was conducted.
[Rule 1303(a)(1) - BACT, Rule 1303(b)(2) - Offset, Rule 2005]

K67.1 The operator shall keep records in a manner approved by the District, for the following parameter(s) or item(s):

Natural gas fuel use after CEMS certification
Natural gas fuel use during the commissioning period
Natural gas fuel use after the commissioning period and prior to CEMS certification
[Rule 2012]

(SCR/CO Catalyst)

A195.4 The 5 ppmv NH3 emission limit is averaged over 60 minutes at 15% O2, dry basis. The operator shall calculate and continuously record the NH3 slip concentration using the following:

NH3 (ppmv) = [a-b*c/1EE+06]*1EE+06/b

where,
a = NH3 injection rate (lbs/hr)/17(lb/lb-mol)
b = dry exhaust gas flow rate (scf/hr)/385.3 scf/lb-mol)
c = change in measured NOx across the SCR (ppmvd at 15% O2)

The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppmv accurate to plus or minus 5 percent calibrated at least once every twelve months.
The NOx analyzer shall be installed and operated within 90 days of initial start-up.
The operator shall use the above described method or another alternative method approved by the Executive Officer.
The ammonia slip calculation procedures described above shall not be used for compliance determination or emission information without corroborative data using an approved reference method for the determination of ammonia.
[Rule 1303(a)(1) - BACT, Rule 2012]

D12.2 The operator shall install and maintain a(n) flow meter to accurately indicate the flow rate of the total hourly throughput of injected ammonia.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent.
It shall be calibrated once every twelve months.
[Rule 1303(a)(1) - BACT, Rule 2005]

D12.3 The operator shall install and maintain a(n) temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent.
It shall be calibrated once every twelve months.
[Rule 1303(a)(1) - BACT, Rule 2005]

D12.4 The operator shall install and maintain a(n) pressure gauge to accurately indicate the differential pressure across the SCR catalyst bed in inches of water column.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent.
It shall be calibrated once every twelve months.
[Rule 1303(a)(1) - BACT, Rule 2005]

E179.1 For the purpose of the following condition number(s), continuously record shall be defined as recording at least once every hour and shall be calculated based upon the average of the continuous monitoring for that hour.

Condition Number D12.2
Condition Number D12.3
[Rule 1303(a)(1) - BACT]

E179.2 For the purpose of the following condition numbers, continuously record shall be defined as measuring at least once every month and shall be calculated based upon the average of the continuous monitoring for that month.

Condition Number: D12.4
[Rule 1303(a)(1) - BACT]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 05-AFC-2 project.
[CEQA]

(Ammonia Storage Tank)

C157.1 The operator shall install and maintain a pressure relief valve with a minimum pressure set at 25 psig.
[Rule 1303(a)(1) - BACT]

E144.1 The operator shall vent this equipment, during filling, only to the vessel from which it is being filled.
[Rule 1303(a)(1) - BACT]

E193.1 The operator shall upon completion of construction, operate and maintain this equipment according to the following specifications:

In accordance with all mitigation measures stipulated in the final California Energy Commission decision for the 05-AFC-2 project.
[CEQA]

(Emergency Fire Pump)

C1.3 The operator shall limit the operating time to no more than 199.99 hours in any one year.

For the purposes of this condition, the operating time is inclusive of time allotted for maintenance and testing
[Rule 1110.2, Rule 1304, Rule 2012]

D12.5 The operator shall install and maintain a(n) non-resettable elapsed meter to accurately indicate the elapsed operating time of the engine.
[Rule 1304, Rule 1470, Rule 2012]

D12.6 The operator shall install and maintain a(n) non-resettable totalizing fuel meter to accurately indicate the fuel usage of the engine.
[Rule 1304, Rule 2012]

B61.1 The operator shall only use diesel fuel containing th3 following specified compounds:

COMPOUND	Range	PPM BY WEIGHT
Sulfur	Less than or equal to	15

[Rule 431.2]

E193.2 The operator shall operate and maintain this equipment according to the following requirements:

1. This equipment shall only operate if utility electricity is not available.
2. This equipment shall only be operated for the primary purpose of providing a backup source of power to drive an emergency fire pump.
3. This equipment shall only be operated for maintenance and testing, not to exceed 50 hours in any one year.
4. This equipment shall only be operated under limited circumstances under a Demand Response Program (DRP).
5. An engine operating log shall be kept in writing, listing the date of operation, the elapsed time, in hours, and the reason for operation. The log shall be maintained for a minimum of 5 years and made available to AQMD personnel upon request.

[Rule 1470, Rule 1110.2]

I296.2 This equipment shall not be operated unless the operator demonstrates to the Executive Officer the facility holds sufficient RTCs to offset the prorated annual emissions increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emissions increase.

To comply with this condition, the operator shall, prior to each compliance year hold a minimum NOx RTCs of 1,851 lbs.

In accordance with Rule 2005(f), unused RTCs may be sold only during the reconciliation period for the fourth quarter of the applicable compliance year inclusive of the 1st compliance year.
[Rule 2005]

K67.2 The operator shall keep records in a manner approved by the Executive Officer, for the following parameter(s) or item(s):

Date of operation, the elapsed time, in hours, and the reason for operation
[Rule 1110.2]

(Section D; Device E32)

K67.3 The operator shall keep records, in a manner approved by the District, for the following parameter(s) or item(s):

For architectural applications where thinners, reducers, or other VOC containing materials are added, maintain daily records for each coating consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings.

For architectural applications where no thinners, reducers, or other VOC containing materials are added, maintain semi-annual records consisting of (a) coating type, (b) VOC content as applied in grams per liter (g/l) of materials used for low-solids coatings, (c) VOC content as applied in g/l of coating, less water and exempt solvent, for other coatings.

WALNUT CREEK ENERGY PROJECT
List of Appendices

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Appendix A - WALNUT CREEK ENERGY PROJECT
LMS100 PA Hourly Emissions - Normal Operations

Data:

Standard Conditions: 29.92 inches Hg and 68 degrees Fahrenheit
Emission Factor (lb/MMBTU) = (controlled ppmvd)*(MW)*(1/SMV)*(20.9/5.9)*(Fd)*(1/1E6)
where,
controlled ppmvd = controlled concentration corrected to 15% O2
MW = molecular weight (lb/lb-mol)
SMV = specific molar volume at 68 degrees Fahrenheit = 385.3 dscf/lb-mol
Fd = dry oxygen F-factor for natural gas = 8,710 dscf/MMBTU at 68 degrees Fahrenheit
Emission Rate Uncontrolled = Emission Factor Uncontrolled (lb/MMBTU) * Heat Input (MMBTU/hr)
Emission Rate Controlled = Emission Factor Controlled (lb/MMBTU) * Heat Input (MMBTU/hr)
Uncontrolled Emissions from the CTG:
NOx = 25 ppm @ 15% O2, CO = 100 ppm @ 15% O2, VOC = 4 ppm, PM10 = 0.0066 lbs/MMBTU; SOx = 0.25 grains/100 scf

CO Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Pollutant Conc. Uncontrolled (ppmvd)	Pollutant Conc. Controlled (ppmvd)	Molecular Weight (lbs/lb-mole)	Specific Molar Volume (dscf/lb-mole)	Dry Fuel Factor (dscf/MMBTU)	Emission Factor Uncontrolled (lb/MMBTU)	Emission Factor Controlled (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	100	6	28	385.3	8,710	0.2242	0.0135	199.93	12.00
103	870.8	100	6	28	385.3	8,710	0.2242	0.0135	195.24	11.71
106	823.2	100	6	28	385.3	8,710	0.2242	0.0135	184.59	11.08
109	824.5	100	6	28	385.3	8,710	0.2242	0.0135	184.86	11.09
112	824.6	100	6	28	385.3	8,710	0.2242	0.0135	184.88	11.09
Average	**846.9**									**11.39**

Appendix A - WALNUT CREEK ENERGY PROJECT
LMS100 PA Hourly Emissions - Normal Operations

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NOx Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Pollutant Conc. Uncontrolled (ppmvd)	Pollutant Conc. Controlled (ppmvd)	Molecular Weight (lb/lb-mol)	Specific Molar Volume (dscf/lb-mole)	Dry Fuel Factor (dscf/MMBTU)	Emission Factor Uncontrolled (lb/MMBTU)	Emission Factor Controlled (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	25	2.5	46	385.3	8,710	0.0921	0.0092	82.11	8.21
103	870.8	25	2.5	46	385.3	8,710	0.0921	0.0092	80.19	8.02
106	823.2	25	2.5	46	385.3	8,710	0.0921	0.0092	75.81	7.58
109	824.5	25	2.5	46	385.3	8,710	0.0921	0.0092	75.92	7.59
112	824.6	25	2.5	46	385.3	8,710	0.0921	0.0092	75.93	7.59
Average	**846.9**									**7.80**

VOC Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Pollutant Conc. Uncontrolled (ppmvd)	Pollutant Conc. Controlled (ppmvd)	Molecular Weight (lb/lb-mol)	Specific Molar Volume (dscf/lb-mol)	Dry Fuel Factor (dscf/MMBTU)	Emission Factor Uncontrolled (lb/MMBTU)	Emission Factor Controlled (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	4	2.0	12	385.3	8,710	0.0038	0.0019	3.43	1.71
103	870.8	4	2.0	12	385.3	8,710	0.0038	0.0019	3.35	1.67
106	823.2	4	2.0	12	385.3	8,710	0.0038	0.0019	3.16	1.58
109	824.5	4	2.0	12	385.3	8,710	0.0038	0.0019	3.17	1.58
112	824.6	4	2.0	12	385.3	8,710	0.0038	0.0019	3.17	1.58
Average	**846.9**									**1.63**

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Appendix A - WALNUT CREEK ENERGY PROJECT
LMS100 PA Hourly Emissions - Normal Operations

PM10 Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Emission Factor[1] (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	0.0067	6.00	6.00
103	870.8	0.0067	5.86	5.86
106	823.2	0.0067	5.54	5.54
109	824.5	0.0067	5.55	5.55
112	824.6	0.0067	5.55	5.55
Average	**846.9**		**5.70**	**5.70**

SOx Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Emission Factor[2] (lb/MMBTU)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Controlled (lb/hr)
100	891.7	0.00068	0.606	0.606
103	870.8	0.00068	0.592	0.592
106	823.2	0.00068	0.560	0.560
109	824.5	0.00068	0.561	0.561
112	824.6	0.00068	0.561	0.561
Average	**846.9**		**0.576**	**0.576**

[1] Based on a manufacturer guarantee of 6 lb/hr at 891.7 MMBTU/hr = 0.00673 lb/MMBTU
[2] Based on a maximum sulfur content of 0.25 grains/100 scf fuel; 1,050 BTU/scf natural gas; and 7,000 grains/lb, and 1 mole S for 2 moles SO_2

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Appendix A - WALNUT CREEK ENERGY PROJECT
LMS100 PA Hourly Emissions - Normal Operations

NH3 Emissions

Operating Condition Number	Heat Input (MMBTU/hr)	Pollutant Conc. Controlled (ppmvd)	Molecular Weight (lb/lb-mol)	Specific Molar Volume (dscf/lb-mol)	Dry Fuel Factor (dscf/MMBTU)	Emission Factor (lb/MMBTU)	Emission Rate (lb/hr)
100	891.7	5	17	385.3	8,710	0.0068	6.07
103	870.8	5	17	385.3	8,710	0.0068	5.93
106	823.2	5	17	385.3	8,710	0.0068	5.60
109	824.5	5	17	385.3	8,710	0.0068	5.61
112	824.6	5	17	385.3	8,710	0.0068	5.61
Average	**846.9**						**5.76**

Appendix A - WALNUT CREEK ENERGY PROJECT
LMS100 PA Hourly Emissions - Start-Up / Shutdown Operations

Data:
Start-up emission factors in the table below were provided in the application by GE
Assumptions
Start-up / shutdown events will not significantly afftect SOx and PM10 emissions. Emission rates are assumed to be equal to normal operations

Start-Up Emissions

Pollutant	Start-Up Emission Factor (lb/event)[1]	Normal Operations (lb/hr)[2]	Normal Operations (lb/hr)[3]	Start-Up Emissions (lbs/hr)
CO	15.4	12.00	5.00	20.40
NOx	7.0	8.21	3.42	10.42
VOC	2.1	1.71	0.71	2.81
PM10	N/A	N/A	N/A	6.00
SOx	N/A	N/A	N/A	0.606

[1] A start-up event is defined as the first 35 minutes of start-up, per GE specs
[2] The emission rates in this column are assumed to occur for 1 full hour
[3]The emission rates inthis column are prorated for the remaining 25 minutes of start-up by multiplying by by 25/60

Shutdown Emissions

Pollutant	Shutdown Emission Factor (lb/event)[4]	Normal Operations (lb/hr)[5]	Normal Operations (lb/hr)[6]	Shutdown Emissions (lb/hr)
CO	18.2	12.00	9.80	28.00
NOx	4.3	8.21	6.70	11.00
VOC	1.6	1.71	1.40	3.00
PM10	N/A	6.00	N/A	6.00
SOx	N/A	0.606	N/A	0.606

[4]Emission rates in this column occur during the first 11 minutes of shutdown, per GE specs
[5]Emission rates in this column are assumed to occur for one full hour
[6]Emission rates in this column are pro-rated for the remaining 49 minutes of shutdown by multiplying by 49/60

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Appendix B - WALNUT CREEK ENERGY PROJECT
LMS100 PA Monthly Emissions - Commissioning Year

Operating Condition 100	Hours per Month	CO (lbs/hr)	NOx (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx (lbs/hr)	CO (lbs/month)	NOX (lbs/month)	VOC (lbs/month)	PM10 (lbs/month)	SOx (lbs/month)
Unit 1 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 1 Commissioning[1]	15	72.60	71.21	2.81	4.01	0.34	1,089	1,068	42	60	5
Unit 1 Normal Operation	368	12.00	8.21	1.71	6.00	0.61	4,416	3,021	629	2,208	223
Unit 1 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 1 Totals	**463**						**7,441**	**4,946**	**904**	**2,748**	**277**
Unit 2 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 2 Commissioning[1]	15	72.60	71.21	2.81	4.01	0.34	1,089	1,068	42	60	5
Unit 2 Normal Operation	368	12.00	8.21	1.71	6.00	0.61	4,416	3,021	629	2,208	223
Unit 2 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 2 Totals	**463**						**7,441**	**4,946**	**904**	**2,748**	**277**
Unit 3 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 3 Commissioning[1]	15	72.60	71.21	2.81	4.01	0.34	1,089	1,068	42	60	5
Unit 3 Normal Operation	368	12.00	8.21	1.71	6.00	0.61	4,416	3,021	629	2,208	223
Unit 3 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 3 Totals	**463**						**7,441**	**4,946**	**904**	**2,748**	**277**
Unit 4 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 4 Commissioning[1]	15	72.60	71.21	2.81	4.01	0.34	1,089	1,068	42	60	5
Unit 4 Normal Operation	368	12.00	8.21	1.71	6.00	0.61	4,416	3,021	629	2,208	223
Unit 4 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 4 Totals	**463**						**7,441**	**4,946**	**904**	**2,748**	**277**
Unit 5 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 5 Commissioning[1]	15	72.60	71.21	2.81	4.01	0.34	1,089	1,068	42	60	5
Unit 5 Normal Operation	368	12.00	8.21	1.71	6.00	0.61	4,416	3,021	629	2,208	223
Unit 5 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 5 Totals	**463**						**7,441**	**4,946**	**904**	**2,748**	**277**
Total Monthly Emissions (lb/month)							37,205	24,731	4,519	13,741	1,383

[1]From Table 12-Proposed Commissioning Schedule in analysis; totals divided by 5 turbines and divided by 134 hours

Appendix B - WALNUT CREEK ENERGY PROJECT
LMS100 PA Monthly Emissions - Non-Commissioning Year

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Operating Condition 100	Hours per Month	CO (lb/hr)	NOx (lb/hr)	VOC (lb/hr)	PM10 (lb/hr)	SOx (lb/hr)	CO (lb/month)	NOX (lb/month)	VOC (lb/month)	PM10 (lb/month)	SOx (lb/month)
Unit 1 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 1 Normal Operations	383	12.00	8.21	1.71	6.00	0.61	4,596	3,144	655	2,298	232
Unit 1 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 1 Totals	**463**						**6,532**	**4,001**	**887**	**2,778**	**281**
Unit 2 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 2 Normal Operations	383	12.00	8.21	1.71	6.00	0.61	4,596	3,144	655	2,298	232
Unit 2 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 2 Totals	**463**						**6,532**	**4,001**	**887**	**2,778**	**281**
Unit 3 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	480	112	240	24
Unit 3 Normal Operations	383	12.00	8.21	1.71	6.00	0.61	4,596	3,144	655	2,298	232
Unit 3 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 3 Totals	**463**						**6,532**	**4,064**	**887**	**2,778**	**281**
Unit 4 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 4 Normal Operations	383	12.00	8.21	1.71	6.00	0.61	4,596	3,144	655	2,298	232
Unit 4 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 4 Totals	**463**						**6,532**	**4,001**	**887**	**2,778**	**281**
Unit 5 Start-Up	40	20.40	10.42	2.81	6.00	0.61	816	417	112	240	24
Unit 5 Normal Operations	383	12.00	8.21	1.71	6.00	0.61	4,596	3,144	655	2,298	232
Unit 5 Shutdown	40	28.00	11.00	3.00	6.00	0.61	1,120	440	120	240	24
Unit 5 Totals	**463**						**6,532**	**4,001**	**887**	**2,778**	**281**
Total Monthly Emissions (lb/month)							32,660	20,069	4,437	13,890	1,403

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Appendix B - WALNUT CREEK ENERGY PROJECT
LMS100 PA - 30 Day Averages[1,2] - Commissioning Year

Operating Condition 100	Hours per Month	CO (lb/hr)	PM10 (lb/hr)	VOC (lb/hr)	SOx (lb/hr)	CO (lb/month)	PM10 (lb/month)	VOC (lb/month)	SOx (lb/month)
Unit 1 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 1 Commissioning	15	72.60	4.01	2.81	0.338	1,089	60	42	5
Unit 1 Normal Operations	368	12.00	6.00	1.71	0.606	4,416	2,208	629	223
Unit 1 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 2 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 2 Commissioning	15	72.60	4.01	2.81	0.338	1,089	60	42	5
Unit 2 Normal Operations	368	12.00	6.00	1.71	0.606	4,416	2,208	629	223
Unit 2 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 3 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 3 Commissioning	15	72.60	4.01	2.81	0.338	1,089	60	42	5
Unit 3 Normal Operations	368	12.00	6.00	1.71	0.606	4,416	2,208	629	223
Unit 3 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 4 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 4 Commissioning	15	72.60	4.01	2.81	0.338	1,089	60	42	5
Unit 4 Normal Operations	368	12.00	6.00	1.71	0.606	4,416	2,208	629	223
Unit 4 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 5 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 5 Commissioning	15	72.60	4.01	2.81	0.338	1,089	60	42	5
Unit 5 Normal Operations	368	12.00	6.00	1.71	0.606	4,416	2,208	629	223
Unit 5 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
						lb/month	**lb/month**	**lb/month**	**lb/month**
Total Monthly Emissions (lb/month)						37,205	13,741	4,519	1,383
						lb/day	**lb/day**	**lb/day**	**lb/day**
30-Day Average (lb/day)						**1,240**	**458**	**151**	**46**

[1] WCEP will be in NOx RECLAIM. As such NOx will be offset with RTCs, and therefore no entries for NOx are included in the table below

Appendix B - WALNUT CREEK ENERGY PROJECT
LMS100 PA - 30 Day Averages[1,2] - Non-Commissioning Year

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Operating Condition 100	Hours per Month	CO (lb/hr)	PM10 (lb/hr)	VOC (lb/hr)	SOx (lb/hr)	CO (lb/month)	PM10 (lb/month)	VOC (lb/month)	SOx (lb/month)
Unit 1 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 1 Commissioning	0	72.60	4.01	2.81	0.606	0	0	0	0
Unit 1 Normal Operations	383	12.00	6.00	1.71	0.606	4,596	2,298	655	232
Unit 1 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 2 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 2 Commissioning	0	72.60	4.01	2.81	0.606	0	0	0	0
Unit 2 Normal Operations	383	12.00	6.00	1.71	0.606	4,596	2,298	655	232
Unit 2 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 3 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 3 Commissioning	0	72.60	4.01	2.81	0.606	0	0	0	0
Unit 3 Normal Operations	383	12.00	6.00	1.71	0.606	4,596	2,298	655	232
Unit 3 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 4 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 4 Commissioning	0	72.60	4.01	2.81	0.606	0	0	0	0
Unit 4 Normal Operations	383	12.00	6.00	1.71	0.606	4,596	2,298	655	232
Unit 4 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
Unit 5 Startup	40	20.40	6.00	2.81	0.606	816	240	112	24
Unit 5 Commissioning	0	72.60	4.01	2.81	0.606	0	0	0	0
Unit 5 Normal Operations	383	12.00	6.00	1.71	0.606	4,596	2,298	655	232
Unit 5 Shutdown	40	28.00	6.00	3.00	0.606	1,120	240	120	24
						lb/month	**lb/month**	**lb/month**	**lb/month**
Total Monthly Emissions (lb/month)						32,660	13,890	4,437	1,403
						lb/day	**lb/day**	**lb/day**	**lb/day**
30-Day Average (lb/day)						**1,089**	**463**	**148**	**47**

[1] WCEP will be in NOx RECLAIM. As such NOx will be offset with RTCs, and therefore no entries for NOx are included in the table below

Appendix C - WALNUT CREEK ENERGY PROJECT
LMS100 PA Annual Emissions - Commissioning Year

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Operating Condition 100	Hours per Year	CO (lbs/hr)	NOx (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx (lbs/hr)	CO (lbs/year)	NOX (lbs/year)	VOC (lbs/year)	PM10 (lbs/year)	SOx (lbs/year)
Unit 1 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 1 Commissioning[1]	134	72.60	71.21	2.81	4.01	0.34	9,728	9,542	377	537	45
Unit 1 Normal Operation	2,634	12.00	8.21	1.71	6.00	0.61	31,608	21,625	4,504	15,804	1,596
Unit 1 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 1 Totals	**3,468**						**58,276**	**38,664**	**6,914**	**20,541**	**2,066**
Unit 2 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 2 Commissioning[1]	134	72.60	71.21	2.81	4.01	0.34	9,728	9,542	377	537	45
Unit 2 Normal Operation	2,634	12.00	8.21	1.71	6.00	0.61	31,608	21,625	4,504	15,804	1,596
Unit 2 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 2 Totals	**3,468**						**58,276**	**38,664**	**6,914**	**20,541**	**2,066**
Unit 3 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 3 Commissioning[1]	134	72.60	71.21	2.81	4.01	0.34	9,728	9,542	377	537	45
Unit 3 Normal Operation	2,634	12.00	8.21	1.71	6.00	0.61	31,608	21,625	4,504	15,804	1,596
Unit 3 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 3 Totals	**3,468**						**58,276**	**38,664**	**6,914**	**20,541**	**2,066**
Unit 4 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 4 Commissioning[1]	134	72.60	71.21	2.81	4.01	0.34	9,728	9,542	377	537	45
Unit 4 Normal Operation	2,634	12.00	8.21	1.71	6.00	0.61	31,608	21,625	4,504	15,804	1,596
Unit 4 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 4 Totals	**3,468**						**58,276**	**38,664**	**6,914**	**20,541**	**2,066**
Unit 5 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 5 Commissioning[1]	134	72.60	71.21	2.81	4.01	0.34	9,728	9,542	377	537	45
Unit 5 Normal Operation	2,634	12.00	8.21	1.71	6.00	0.61	31,608	21,625	4,504	15,804	1,596
Unit 5 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 5 Totals	**3,468**						**58,276**	**38,664**	**6,914**	**20,541**	**2,066**
Total Annual Emissions (lb/year)							**291,382**	**193,321**	**34,571**	**102,707**	**10,328**

[1]From Table 12-Proposed Commissioning Schedule in analysis; totals divided by 5 turbines

Appendix C - WALNUT CREEK ENERGY PROJECT
LMS100 PA Annual Emissions - Non-Commissioning Year

Operating Condition 100	Hours per Year	CO (lbs/hr)	NOx (lbs/hr)	VOC (lbs/hr)	PM10 (lbs/hr)	SOx (lbs/hr)	CO (lbs/year)	NOX (lbs/year)	VOC (lbs/year)	PM10 (lbs/year)	SOx (lbs/year)
Unit 1 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 1 Normal Operations	2768	12.00	8.21	1.71	6.00	0.61	33,216	22,725	4,733	16,608	1,677
Unit 1 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 1 Totals	**3,468**						**50,156**	**30,222**	**6,767**	**20,808**	**2,102**
Unit 2 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 2 Normal Operations	2768	12.00	8.21	1.71	6.00	0.61	33,216	22,725	4,733	16,608	1,677
Unit 2 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 2 Totals	**3,468**						**50,156**	**30,222**	**6,767**	**20,808**	**2,102**
Unit 3 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 3 Normal Operations	2768	12.00	8.21	1.71	6.00	0.61	33,216	22,725	4,733	16,608	1,677
Unit 3 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 3 Totals	**3,468**						**50,156**	**30,222**	**6,767**	**20,808**	**2,102**
Unit 4 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 4 Normal Operations	2768	12.00	8.21	1.71	6.00	0.61	33,216	22,725	4,733	16,608	1,677
Unit 4 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 4 Totals	**3,468**						**50,156**	**30,222**	**6,767**	**20,808**	**2,102**
Unit 5 Start-Up	350	20.40	10.42	2.81	6.00	0.61	7,140	3,647	984	2,100	212
Unit 5 Normal Operations	2768	12.00	8.21	1.71	6.00	0.61	33,216	22,725	4,733	16,608	1,677
Unit 5 Shutdown	350	28.00	11.00	3.00	6.00	0.61	9,800	3,850	1,050	2,100	212
Unit 5 Totals	**3,468**						**50,156**	**30,222**	**6,767**	**20,808**	**2,102**
Total Annual Emissions (lb/year)							**250,780**	**151,111**	**33,834**	**104,040**	**10,508**

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Appendix D - WALNUT CREEK ENERGY PROJECT
Emergency Fire Pump Emissions

Data:
Standard Conditions: 29.92 inches Hg and 68 degrees Fahrenheit
Manufacturer: Clarke
Model No.: JW6H-UF50
Type of Fuel: No. 2 Diesel w/ 0.05% sulfur compounds by weight
Rated Power: 340 bhp at 2,100 rpm
Engine Design: Lean Burn
Maximum Rated Fuel Consumption: 16.0 gph
No. of Cylinders: 6

Assumptions:
Maximum hours of operation: 199 hours/year
Steady speed, steady load operations

Pollutant	Emission Factor[6] (lb/BHP-hr)	Emission Factor[7] (gm/BHP-hr)	Maximum Rated Power (BHP)	Conversion Factor (gm/lb)	Emission Rate (lb/hr)	Annual Emission Rate[8] (lb/year)	Monthly Emission Rate[9] (lb/month)	30 Day Average[10] (lb/day)
NOx	0.031		340	454	10.540	2097.46	174.79	6
CO		0.27	340	454	0.202	40.24	3.35	0
VOC		0.15	340	454	0.112	22.35	1.86	0
PM10		0.09	340	454	0.067	13.41	1.12	0
SOx		0.0055	340	454	0.0041	0.82	0.07	0

[6] NOx is based on the factor found in Table 3.3-1 of AP-42; NOx = 0.031 lb/bhp-hr.
[7] Provided by the engine manufacturer (Clarke)
[8] Emission rate (lb/hr) multiplied by 199
[9] Emission rate (lb/year) divided by 12
[10] Emission rate (lb/month) divided by 30

Appendix E - WALNUT CREEK ENERGY PROJECT
Cooling Tower Emissions

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Data:
Manufacturer: Marley
No. of cells: 5
Drift Loss: 0.0005%
Maximum TDS in Circulating Water: 5,000 mg/l
Circulating Water Rate: 35,500 gpm
Fan Exit Height : 39.09 ft AGL
Exhaust Fan Diameter: 22 ft
PM10 Emissions (lb/hr) = (Maximum TDS)*[(3.785*60)/(454*1000)]*(Circulating Water Rate)*(Drift Loss)
Water Source: Reclaimed/Recycled Water
Tower Dimensions: Deck Height: 27.09 ft AGL; Deck Length: 210.7 ft; Deck Width: 36.67 ft

Assumptions:
Cooling tower emissions based on 3,468 hr/yr operation
100% of TDS in solution is converted to PM10 at a drift loss of 0.0005%

Pollutant	Maximum TDS in circulating water (mg/l)	Circulating Water Rate (gpm)	Drift Loss (percent)	PM10 Emissions (lb/hr)	PM10 Emissions (lb/year)	PM10 Emissions[11] (lb/month)	30 Day Average[12] (lb/day)
PM10	5,000	35,500	0.00050	0.4439	1,539.60	128.30	4

[11] PM10 emissions (lb/year) divided by 12
[12] PM10 emissions (lb/month) divided by 30

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Appendix F - WALNUT CREEK ENERGY PROJECT
NOx RTC Calculations

Data:
Operating Schedule (1st Year):
Startups = 350 hours/year
Shutdowns = 350 hours/year
Normal Operations = 2,634 hours/year
Commissioning Period =134 hours

Operating Condition 100	Hours per Year	NOx (lb/hr)	NOx (lb/year) per device	NOx (lb/year) cumulative
CTGs				
Startup	350	10.42	3,647.00	18,235.00
Shutdown	350	11.00	3,850.00	19,250.00
Normal Operation	2,634	8.21	21,625.14	108,125.70
Commissioning	134	71.21	9,542.14	47,710.70
CTG Totals	3,468		38,664.28	193,321.40
Emergency Fire Pump	199	10.54	2,097.46	2,097.46
Total 1st Year Emissions (lb/year)			40,761.74	195,418.86
Offset Ratio			1.00	1.00
1st year RTCs (lb/year)			**40,761.74**	**195,418.86**
2nd year RTCs (lb/year)			**31,219.60**	**147,708.16**

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Appendix G - WALNUT CREEK ENERGY PROJECT

Emission Factors[1]

Total Annual Hours of Operation = 3,468 hours
Total Hours of Commissioning = 134 hours
Total Hours During Non-Commissioning = 3,334 hours

Fuel Consumption During the Commissioning Period

Commissioning Schedule	Hours per Phase	Heat Input (MMBTU/hr)	Fuel Heating Value (BTU/scf)	Fuel Consumption (MMscf/hr)	Fuel Consumption per Phase (MMscf)	Cumulative Fuel Cons. during Comm. (MMscf)
Phase 1	20	750	1,050	0.7143	14.2857	14.2857
Phase 2	14	900	1,050	0.8571	12.0000	26.2857
Phase 3	24	2500	1,050	2.3810	57.1429	83.4286
Phase 4	12	4,503	1,050	4.2886	51.4629	134.8914
Phase 5	24	3,500	1,050	3.3333	80.0000	214.8914
Phase 6	40	4,503	1,050	4.2886	171.5429	386.4343

Commissioning Period Emission Factor

Commissioning Schedule	Fuel Consumption per Phase (MMscf)	NOx Emissions per Phase (lb)	CO Emissions per Phase (lb)	NOx EF lb/mmscf	CO EF lb/mmscf
Phase 1	14.2857	9,100	5,500		
Phase 2	12.0000	6,930	4,200		
Phase 3	57.1429	21,000	20,160		
Phase 4	51.4629	4,860	15,300		
Phase 5	80.0000	4,200	1,080		
Phase 6	171.5429	1,620	2,400		
TOTALS	386.4343	47,710	48,640	**123.46**	**125.87**

[1] The heat input values, fuel consumptions, and emissions during each phase of commissioning are for all five CTGs

Appendix G - WALNUT CREEK ENERGY PROJECT
Emission Factors[2]

Annual fuel consumption (AFC) during non-commissioning is calculated as follows:
AFC = (5 CTGs)(891.7 MMBTU/hr)(1 scf/1,050 BTU)(3,334 hr/yr) = 14,156.7 MMscf/yr

Emissions During the Non-Commissioning Period

Total NOx Emissions (lb/yr)	Total CO Emissions (lb/yr)	Total SOx Emissions (lb/yr)	AFC (MMscf/yr)	NOx EF lb/mmscf	CO EF lb/mmscf
153,736	261,280	10,508	14,156.7	**10.8596**	**18.4563**

[2] The total NOx, CO and SOx emissions as well as the AFC are for all 5 CTGs

Emission Factor Determination for Condition A63.1 & A63.2

PM10 EF lb/MMBTU	SOx EF gr/100 scf	VOC EF lb/MMBTU	Grains/lb	Heat Content BTU/scf	PM10 lb/mmscf	SOx lb/mmscf	VOC lb/mmscf
0.0066	0.250	0.0019	7,000	1,050	**6.93**	**0.7143**	**1.9950**